VICTORIA UNIVERSITY OF WELLINGTON
TE HERENGA WAKA
NEW ZEALAND
Archives of Sustainable Energy Systems
https://www.wgtn.ac.nz/sustainable-energy-systems

Reduce stress on local distribution transformers through load, battery control, and photovoltaics: A Wellington case study

Kittiphonh Phengthavongsa, Daniel Burmester

Abstract

The growth of electric vehicles (EVs) and photovoltaic (PV) generation introduces new operational challenges for low voltage (LV) distribution networks, including transformer overloading, voltage deviations and bidirectional power flows. Mitigation measures often include the upgrading of conventional transformers and the re-conductoring of feeders. These methods become inefficient for uncertain load-growth paths. The technical effectiveness of coordinated distributed energy resources (DERs), such as rooftop PV systems, battery energy storage systems (BESS), and EV charging as non-wires alternatives (NWAs) to reduce the operational stress on local distribution transformers (LDTs) is assessed in this study. The representative Wellington suburban LV feeder is a 656-household feeder with 500-1000 kVA transformers. The feeder is modelled in DIgSILENT PowerFactory 2024 using the quasi-dynamic simulation language (QDSL) time-series at hourly resolution for one year. Four progressive scenarios are considered: (i) baseline operation without DERs, (ii) increasing PV penetration levels (5% in 2030, 10% in 2035, 28% in 2050), (iii) increasing number of EVs as load (5% in 2030, 10% in 2035, 28% in 2050) and (iv) integration of community-scale BESS for peak shaving. The results show that coordinated operation of DERs with BESSs can reduce transformer peak loading and improve voltage compared to standalone PV. In particular, the transformer-aware BESS dispatch offers a measurable peak shaving capacity and improves the local energy balancing, enabling a higher renewable penetration with less conventional infrastructure reinforcement. The practical role of DER coordination in improving LV network are more resilience and defers investment in the distribution systems as a scalable approach.

Keywords: Distributed Energy resources (DERs); photovoltaic (PV) systems; battery energy storage systems (BESS); electric vehicles (EVs); Low voltage (LV).

1. Introduction

Low-voltage distribution networks are under rapid structural change due to increasing electrification and the widespread adoption of distributed energy resources (DERs) in photovoltaic (PV) systems, Battery Energy Storage Systems (BESS) and electric vehicles (EVs). While these technologies support the decarbonisation idea, they also introduce operational challenges for distribution network operators, including transformer overloading, overvoltage, reverse power flow, and increased feeder utilisation during peak demand periods (Guo et al., 2021; Majeed and Nwulu 2022; Krishneel Prakash et al., 2022).

These main impacts occur in residential LV feeders, where the infrastructure is originally designed for passive one-directional power delivery rather than active bidirectional energy exchange. This means that the rapid growth of renewable energy sources (RES) reshapes the way distribution networks operate. Traditionally, electricity flowed in a single direction from large, centralised generators to end users. However, with the increasing deployment of distributed resources in PV and BESS, distribution systems must now manage bidirectional, variable power flows to benefit from reduced transformer stress (Datta et al., 2020).

In this context, BESS becomes a more important technology, supporting the balance between supply and demand, reducing the variability of renewable generation, and contributing to overall grid stability (Garttan et al., 2025). As a result, distribution networks are no longer passive systems but are expected to actively deliver services such as frequency regulation, voltage support, congestion management, and even black-start capability (Stecca et al., 2020; Meng et al., 2021; Srivastava et al., 2023; Prastia et al., 2024).

Besides these opportunities, there are many challenges associated with the integration of RES and BESS at the low-voltage (LV) level. Many existing infrastructure components, especially local distribution transformers, are not designed to handle highly variable demand or bidirectional power flows (Boston Consulting Group 2022). Increasing demand for electricity and electrification trends are placing more pressure on the distribution network in Wellington. Similar concerns are arising locally (Wellington Electricity, 2025). Such challenges increase the interest in non-traditional solutions, such as the deployment of BESS and integration of PV. These approaches can possibly prevent or postpone conventional network reinforcement and add to the system's resilience and cost-effectiveness.

Therefore, the research gap is transformer overloading. One of the key challenges in modern distribution networks is the increasing demand for EV loads at the LV level. This can lead to the transformer being under more stress and the asset having a shorter lifespan (Boston Consulting Group 2022; Wellington Electricity 2025). BESS can mitigate this issue, but still, there is a research gap regarding the optimal sizing and control of BESS to reduce transformer overloading under realistic operating conditions (Mohamed et al, 2020; Meng et al, 2021).

The core rationale of this study is to assess whether operational coordination of DERs can technically extend transformer life while supporting higher levels of renewable integration and contributing to decarbonisation goals. This study investigates the technical effectiveness of coordinated DER deployment as a transformer-stress mitigation strategy, using a representative residential LV feeder in Wellington, Aotearoa New Zealand. A simulation-based methodology is implemented in DIgSILENT PowerFactory 2024 to evaluate progressive DER integration scenarios, including EV charging, increasing PV penetration levels, and centralised and decentralised BESS deployment.

1.1. Research objective

The objective of this research is to explore the possibility of extending the transformer's service capability and delaying conventional reinforcement investment through coordinated DER operation, while supporting higher renewable penetration in the distribution networks. For this purpose, the case study of the Wellington feeder, Kilbourne, is selected as a representative of Aotearoa New Zealand's electricity distribution systems. The research aims to evaluate the effectiveness of coordinated DERs, rooftop PV systems and BESS in reducing the operational stress on local distribution transformers under increasing load conditions driven by EV penetration. In this study, EV charging is considered mainly as an additional residential load to increase the peak demand in the evening and to accelerate the transformer utilisation. The main objectives are:

- To evaluate the impact of EV load charging on distribution transformer loading in low-voltage networks;

- To investigate the combined impact of coordinated PV and BESS control strategies on reducing transformer utilisation levels; and
- To determine whether coordinated distributed energy resources (DERs) can function as a practical non-wires alternative (NWA) to defer conventional transformer capacity upgrades under increasing electrification demand.

2. Literature review

The purpose of this literature review is to examine how BESS has been studied in LV networks, particularly for supporting RES integration, EV charging demand, voltage control, congestion management, peak shaving, and transformer stress reduction. The review also identifies how previous studies have addressed these issues through BESS sizing, placement, control strategies, and optimisation methods. By grouping the literature into key research clusters, this review highlights which areas are directly relevant to LV transformer stress reduction rather than frequency regulation and black-start which are mainly related to the transmission.

2.1. Review approach and outcome

Scopus, Google Scholar, and IEEE Explore were used with a Boolean search string: Battery OR Battery energy storage systems (BESS) AND Ancillary Services AND distribution grid. The final dataset was analysed through publication trends, keyword frequency, and thematic clustering. From this process, it was found that the literature is divided into four major research clusters:

1. Economics and policy: Topics such as battery degradation, cost-benefit analysis and regulation are addressed in the economics and policy cluster, which suggests that financial viability and institutional conditions are significant barriers to the practical implementation of BESS.
2. Grid operations: The grid operations cluster focuses on voltage control, reactive power, adaptive control, power quality, and voltage regulation, showing the importance of BESS in maintaining local network performance.
3. Integration and efficiency: Integration and efficiency cluster: Model predictive control, power smoothing, congestion management, renewable integration, peak shaving and demand response. This is consistent with the role of BESS in improving system flexibility and alleviating network stress.
4. Stability and frequency: The stability and frequency cluster is dominated by system stability, primary frequency control, and frequency regulation, with additional attention to black-start, frequency response, and grid-forming inverter technologies.

Therefore, based on these clusters, the outcome is further divided into two broad categories:

1. Short-term ancillary services such as frequency regulation, voltage support, and black-start capability; and
2. Long-term ancillary services such as congestion management, peak shaving, and power smoothing.

2.2. Review discussion

The four clusters are not equally relevant to the objective of this study, which focuses on reducing stress on local distribution transformers in LV networks under increasing RES, BESS, and EV penetration. Grid operations are highly relevant because they directly relate to voltage control, power quality, reverse power flow, feeder loading, and transformer operating limits. Integration and efficiency are also highly relevant because they cover peak shaving, congestion management, PV–BESS coordination, demand response, and BESS sizing and control. Economics and policy are relevant, but they are discussed more briefly because the main focus of this study is technical transformer stress reduction rather than market design or investment analysis. However, this cluster remains important because BESS deployment depends on cost, ownership, battery degradation, and revenue mechanisms. Stability and frequency are also included, but mainly as supporting background. Many studies in this cluster focus on wider system stability, frequency regulation, black-start, and grid-forming inverter operation, which are often associated with transmission-level or whole-system ancillary services. These topics are important for understanding BESS capability, but they are less directly connected to local LV transformer stress. Therefore, the discussion topic includes the battery in the distribution network, battery degradation, and ownership and market regulation

2.2.1. Battery in distribution network

BESSs have become an important technology for supporting modern distribution networks with increasing renewable energy sources (RES), photovoltaic (PV) generation, and electric vehicle (EV) charging. The traditional load behaviour in distribution networks is usually predictable. However, the rapid uptake of EVs and rooftop PV systems introduces more variable and distributed demand patterns, which increase operational complexity for network operators (Fachrizal et al., 2021). However, the increasing penetration of distributed energy resources has changed the operating behaviour of distribution networks by creating variable demand, intermittent generation, bidirectional power flow, and local voltage variation (Datta et al., 2020; Fachrizal et al., 2021; Mamun et al., 2022). These changes are particularly important at the low-voltage (LV) level, where local transformers, feeders, and lines were not originally designed to manage highly variable loading or reverse power flow.

One of the major problems in LV distribution networks is the increasing stress on local distribution transformers. Existing studies show that high PV penetration and EV charging can increase voltage variation, reverse power flow, frequency regulation, peak shaving, power smoothing and transformer loading. Majeed (2022) states that reverse power flow from high PV penetration can overload distribution transformers and reduce their operating life. Fokui (2022) examines controlled EV charging as a way to manage reverse power flow in PV-rich LV networks. Prakash (2022) reviews BESS applications for ancillary services in distribution grids, including voltage support, frequency regulation, black-start, peak shaving, congestion relief, and power smoothing. The charging of EVs also can increase the peak demand in the evening and congestion in local areas, but PV generation surplus can charge directly to battery solving this kind problem throughout the voltage regulation (Uzum et al., 2021; Srivastava et al., 2023). The uncoordinated EV charging may lead to overloads of distribution transformers and increase the asset ageing, particularly with high-speed charging, increasing the peak-to-average load ratio(Soleimani and Kezunovic 2020; Zheng et al., 2021). Kamana-Williams et al. (2024) also state that unmanaged EV charging may lead to large increases in transformer loading during peak periods. Similarly, (Majeed and Nwulu, 2022) find that high PV penetration in LV networks can lead to transformers being overloaded and reduce their lifetime if the reverse power flow is not properly managed. The studies show that the timing, location and coordination of PV generation, EV charging and household load all impact transformer stress, in addition to total demand growth.

BESS are proposed to be a flexible means to reduce these impacts. BESS can reduce transformer loading, improve voltage performance, smooth power flow and defer network reinforcement by charging during low demand or high-PV periods and discharging during peak demand. Prakash (2022) find BESS as a promising technology for the provision of short-term and long-term ancillary services such as voltage support, frequency regulation, congestion relief, peak shaving and power smoothing. Kryonidis et al. (2021) also demonstrate that strategic charging/discharging of the BESS can balance power flows, reduce equipment overloading and improve the reliability of the distribution network. Stecca et al. (2020) demonstrated that the integration of PV and BESS in hybrid AC/DC grids can alleviate transformer overloading during peak demand. Ahmed et al. (2022) also show that the voltage rise and congestion in LV networks can be reduced by aligning the BESS charging with the PV export.

BESS support renewable integration, grid flexibility, and LV network operation. The literature also shows that the effectiveness of BESS is highly dependent on its sizing, placement and control strategy. Al-Saffar and Musilek (2020) suggest the use of reinforcement learning to coordinate BESS charging and discharging for overvoltage mitigation. Tewari et al. (2021)suggest coordinated control between BESS and on-load tap changers for better voltage regulation in distribution feeders. Jamroen (2022) proves that BESS with state of charge (SoC) management can improve voltage regulation in PV-rich networks, but economic performance is hard to achieve without proper revenue support. Zheng et al. (2022) also study BESS integration with solid-state and hybrid transformers for voltage stability, reverse power flow mitigation and energy arbitrage. These studies show that BESS can provide local voltage support but its performance is dependent on control design, economic conditions and network constraints.

Various studies are conducted for optimal BESS planning and scheduling for transformer loading and congestion management. Prajapati and Mahajan (2021) present a charging and discharging scheme of the BESS to manage the uncertainty of RES and reduce the grid congestion. Mohamed et al. (2020) examine optimal BESS placement and scheduling to ease congestion due to low-carbon technologies. As Laws et al. (2024) mentioned, optimal BESS planning can increase the lifetime of transformers by reducing thermal overload. Nair et al. (2021b)demonstrate the use of model predictive control on PV-battery systems to reduce congestion and degradation of the battery while maintaining high self-consumption. These studies are very relevant to LV networks as the overloading of transformers is a localised problem dependent on the demand of the feeder, PV export, EV charging behaviour and the position of the storage system.

Peak shaving is another important BESS application for transformer stress reduction. Peak shaving is the reduction of demand during high load periods, by shifting or supplying part of the load from storage. BESS operations aim to flatten the load profile, charging the battery during periods of low demand and discharging it during periods of high demand (Prakash et al., 2022). Rana et al. (2022) compare fixed demand limit and decision tree-based peak shaving methods and showed that BESS can reduce peaks and mitigate losses, imbalance and voltage or frequency variation. These studies validate the use of BESS as NWAs where storage can defer or reduce the need for transformer and feeder upgrades.

Power smoothing is also useful in high PV penetration networks. The output of solar PV is affected by cloud movement, seasonal variation, and rapid changes in irradiance resulting in voltage fluctuation and stress on voltage regulating devices (Karmakar and Singh 2021; Abdalla et al., 2023). Datta (2021) demonstrate that BESS can be used as an energy buffer that can store excess PV generation at high irradiance and deliver energy when the PV output is low. Nair et al. (2021a) studied the BESS control based on forecasts to smooth the PV output. Wang et al. (2022) propose model predictive control for real-time BESS dispatch based on PV and load forecasts. Abdalla et a. (2023) have also demonstrated that hybrid control strategies based on BESS, smart inverters, demand response, and predictive control can enhance the smoothing performance and reduce the stress on the batteries. These studies demonstrate the potential of BESS for PV integration improvement. But they also note the importance of balancing the network support and the battery degradation.

However, despite the increased literature on BESS in distribution networks, many works focus on broader ancillary services and system-level stability. Frequency regulation, reserve provision, black-start capability, and grid-forming inverter control are often discussed at the whole system or transmission level. Meng et al. (2021) studied the virtual inertia and droop control of BESS to achieve primary frequency regulation. Zhao et al. (2021) consider the location-dependent BESS control for fast frequency response, and Gouveia et al. (2021) consider the BESS with grid-forming converters in isolated renewable-dominated systems. Gerini et al. (2021) and Syahbani et al. (2025) also discuss inverter control strategies with the potential of grid-forming inverters for virtual inertia, black-start and microgrid support. While these studies are important for the stability of the power-system, they tend to focus on the frequency response, inertia and system-level operation rather than the local LV transformer loading.

This leaves a clear gap for research. While BESS has been widely studied for ancillary services, research on the impact of BESS sizing, placement, and control on mitigating local distribution transformer stress with the increasing penetration of PV and EV is limited. LV transformer stress is a local, time-dependent problem that is dependent on winter peak demand, PV export, feeder loading, EV charging coincidence and battery control logic. Hence, more research is needed to assess the ability of centralised and decentralised BESS layouts to reduce transformer loading, enhance voltage performance and support the future operation of LV networks.

This study builds on the existing literature by focusing on BESS as a non-wires alternative for reducing stress on local distribution transformers. Unlike studies that mainly examine BESS for transmission-level frequency regulation or general ancillary service provision, this work focuses on LV distribution network constraints. The main contribution is to evaluate how BESS configuration and control strategy can reduce transformer overloading under increasing RES, PV, and EV penetration. This provides a more practical basis for future distribution network planning, where BESS may be used alongside PV coordination, EV charging management, and selective network reinforcement.

2.2.2. Battery degradation

The limitation that causes problems is the uncertainty about the degradation and lifetime of batteries. Batteries as ancillary services are required to cycle frequently and to respond quickly, which can accelerate battery ageing and reduce the lifespan of the system, such as a solid-state transformer or controlled ramp rate (Jawad et al., 2021; Lappalainen and Valkealahti, 2022; Zheng et al., 2022). Various models of degradation are discussed, but many of them are either oversimplified and not representative of real operating conditions or are too complex to be implemented in a real time control systems (Soleimani and Kezunovic, 2020; Gui et al., 2024). This creates uncertainty in technical planning and economic assessment.

Degradation and lifetime, including cycle ageing, depth of discharge (DoD), temperature sensitivity, efficiency losses, safety risks and limited recycling infrastructure, also affect battery performance (Nair et al., 2021b; Peng et al., 2021; Kim and Shin, 2023). These factors drive up lifecycle costs and decrease long-term reliability. Mitigation strategies include enhanced thermal management, advanced control strategies (e.g., predictive and AI-based scheduling), the use of long-life chemistries such as lithium iron phosphate (LFP) and predictive maintenance with data-driven degradation modelling (Mexis and Todeschini, 2020; Kim and Shin, 2023; Lin et al., 2023; Chen et al., 2024; Wang et al., 2024).

2.2.3. Ownership and market regulation

BESS deployment faces significant regulatory, market and technical barriers. A key challenge is the lack of clear regulatory frameworks, where storage is not explicitly defined as an asset class, leading to ambiguity in terms of ownership, market participation and operational roles (Gailani et al., 2020; Kumar et al., 2020; Ramos et al., 2021). In addition, uncertain revenue streams from services such as energy arbitrage and frequency regulation expose investors to high financial risk, limiting large-scale adoption (Uzum et al., 2021; Filho et al., 2023). Deployment is also hampered by technical challenges related to grid integration, such as intermittency, harmonics and bidirectional power flow, in the absence of advanced control strategies and supportive policies (Uzum et al., 2021; Gholami et al., 2024).

Challenges are tackled with clear and consistent regulatory frameworks that specify storage roles and allow for fair market participation (Filho et al, 2023). Stable revenue mechanisms such as long-term contracts and flexible markets can lower investment risk and enable service stacking (Gailani et al., 2020; Kumar et al., 2023). However, to overcome the technical challenges for ensuring reliable operation, the deployment of advanced control strategies and the upgrade of grid integration standards are needed (Gouveia et al., 2021; Srivastava et al., 2023). Peer-to-peer trading based on blockchain technology is another emerging approach that provides opportunities for increasing flexibility and generating additional value from BESS deployment (Zheng et al., 2025).

2.3. Review conclusion

In summary, the important points are the proper sizing, coordinated controls, degradation-aware operation, and the supportive regulatory policies for the successful implementation of BESS, to guarantee the technical performance and the long-term economic viability. BESSs are vital for renewable integration and grid flexibility, but encounter severe economic, technical and regulatory challenges. High capital costs and the uncertainty in optimal sizing and control strategies impact the feasibility of projects. Battery degradation, temperature sensitivity and limited recycling infrastructure also reduce lifetime performance and increase lifecycle costs. There are also regulatory issues, such as unclear ownership structures and uncertain revenues from ancillary service markets.

For this study, the long-term ancillary service is the most relevant because it directly relates to reducing stress on distribution transformers in LV networks. Congestion management and peak shaving are closely connected to transformer overloading, feeder constraints, and future demand growth from EV charging. Power smoothing is also relevant because it helps manage the variability of PV generation and reduces fast changing in power flow. In contrast, short-term services such as frequency regulation and black-start are discussed mainly as background, as they are often addressed from transmission-level perspective. Therefore, this classification helps narrow the literature review towards the studies most relevant to BESS placement, sizing, and control for transformer stress reduction.

3. Research methods

This research aims to evaluate the effectiveness of coordinated load and battery control in mitigating transformer overloading and improving the operational performance of LV distribution networks. The main research question guiding this study is to what extent coordinated deployment of loads (house and EV), PV and BESS, can reduce transformer peak loading and defer infrastructure upgrades under realistic load growth scenarios. The representative case study is in Kilbirnie. The Wellington suburban LV feeder comprises 656 households supplied by a 500-1000 kVA transformer.

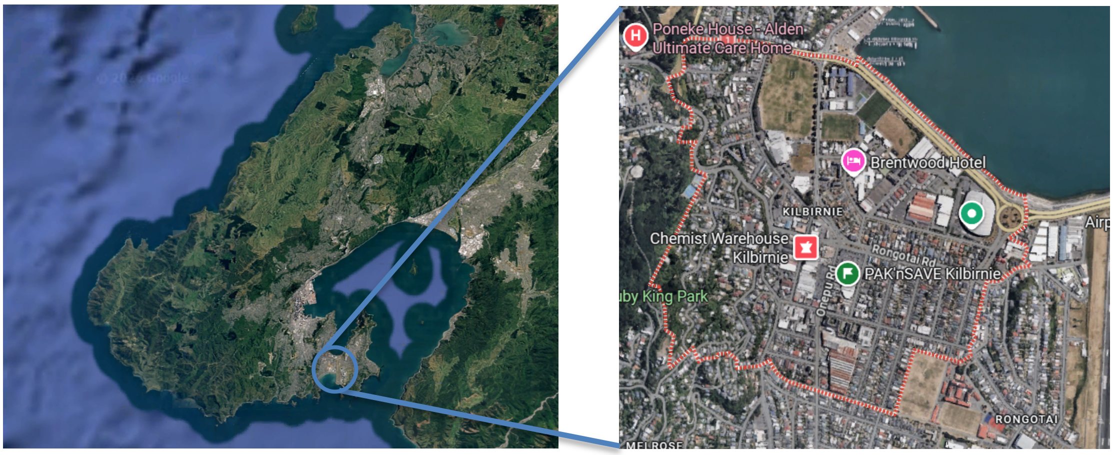


Figure 1. Map and location of the transformer in Kilbirnie, Wellington

3.1. Data collection and sources

Data inputs were drawn from a combination of empirical sources and simulated datasets:

- **Loads**:

  General Loads: The Wellington household load profiles are at fifteen-minute resolution for 24 hours. These are scaled to consider seasonal and daily variation in consumption, including morning and evening peaks. Figure 2 shows Aotearoa New Zealand experiences four seasons each with its own identity load profile (Anderson et al, 2018). Table 1 indicates each seasonal period and energy demand. The load profiles in this research use the data set of the NZ GREEN Grid Household Electricity Demand Data (Anderson et al, 2018). The loads show the seasonal variation in residential electricity demand for heat pumps, hot water, and lighting.

Table 1. Aotearoa New Zealand demand by season

Season	Duration	Energy Demand
Summer	December to February	Medium
Autumn	March to May	Medium
Winter	June to August	High
Spring	September to November	Low to Medium

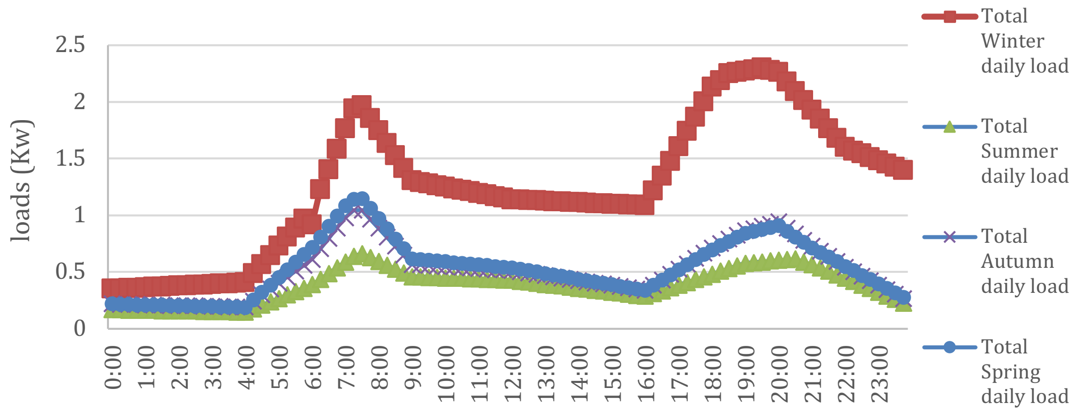


Figure 2. Daily load profile per season in Aotearoa New Zealand

EV Loads: The charging load profiles are based on a 6 kW for three-phase systems with current residential and public charging infrastructure standards following the SNZ PAS 6011:2023 (Standards New Zealand 2023). The study adopts a residential EV charging profile based on research presented in energy consumption Level 1 charging in Figure 3 (Speake et al., 2025). The hourly charging power in a week is derived from the national aggregate profile shown in Figure 4. Level 1 charging is chosen because it is more in line with typical residential overnight charging behaviour. The hourly load profile is normalised over 24 h as a time series with peak charging occurring in the evening hours (around 18:00-22:00) and low activity during the daytime hours (Speake et al., 2025). The profile is scaled to the assumed EV battery capacity and charging period. Wellington Electricity states the percentage of EVs would increase from 6% to 76% for the worst case (Wellington Electricity, 2025). Transpower states 5 scenarios of the percentage of EVs rise (Transpower, 2026). In this research, the EV percentage is opted in the medium range from 6% to 58%.

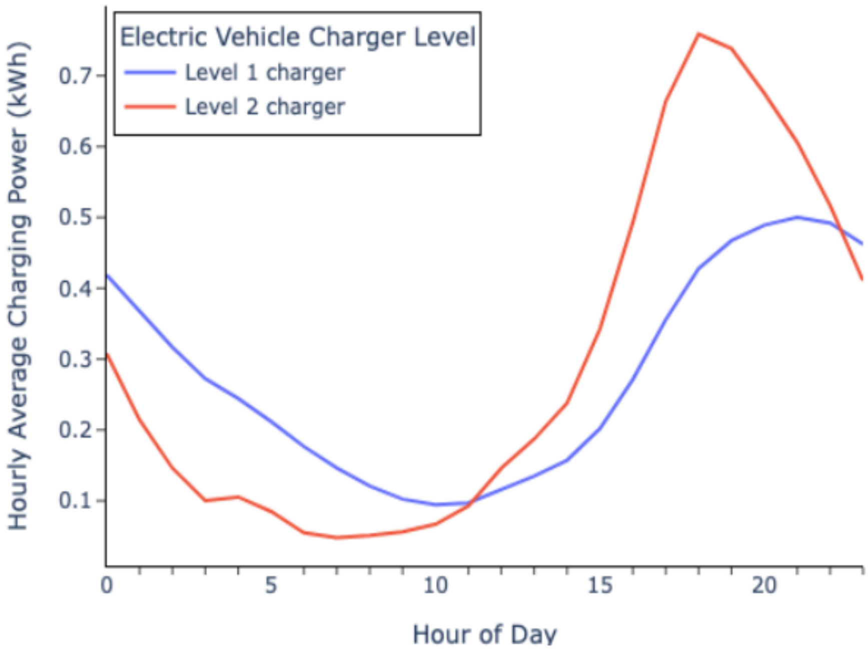


Figure 1. National average EV charger consumption
(Source: Speake et al., 2025)

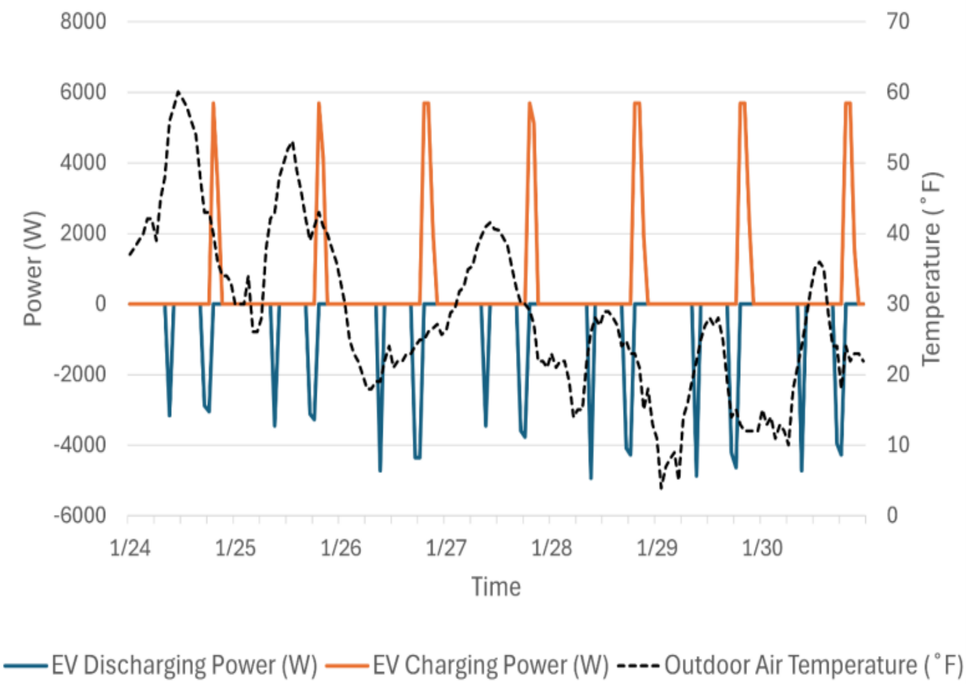


Figure 2. Weekly charging profile of an EV
(Source: Speake et al., 2025)

- **PV generation profiles**: PV generation profiles are generated from PowerFactory geographical profile solar irradiance datasets, adjusted for Wellington's climate conditions. The design parameters, including the performance of the inverter, the orientation of the module, and the tilt angle of the module facing North, are specified by the Standard New Zealand SNZ PAS 6014:2025, and the efficiency of the standard residential solar panels in converting sunlight to electricity is 20–25% (Standards New Zealand, 2025). This research selects the increment of PV generation and observed from 2% to 28% based on the Wellington Electricity data set (Wellington Electricity 2025). In this study, PV is modelled as a 5 kW export to distribution grid in terms of residential-scale installation (Standards New Zealand, 2025).

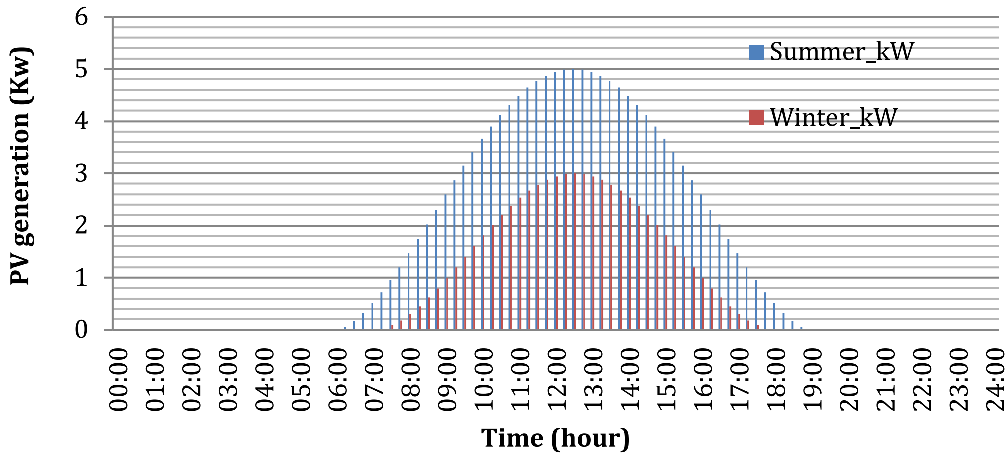


Figure 5. Comparison between Summer and Winter of PV generation

Figure 5 shows that the generation increases from morning, peaks around midday and declines towards the evening in Summer and Winter. The scale of the output is obviously different. The summer profile peaks at a higher value of around 5 kW, and the winter profile peaks at around 3 kW because of the higher solar irradiance in summer. In summer, the generation duration is longer, with PV production starting earlier and ending later. In contrast, the winter profile is shorter and more compressed, meaning less daylight. These differences show that summer has more sustained and higher energy generation, while winter seasonal PV contribution to the system is limited.

- **BESS characteristics**: BESS systems are parameterised as lithium-ion units, with a round-trip efficiency of 90 %, depth of discharge (DoD) limits of 80 %, and cycle degradation around 2% (Gailani et al., 2020; Rahman and Alharbi, 2024; Roy et al., 2024). In this research, the battery consists of two different types: centralised and decentralised batteries. The decentralised batteries are distributed throughout the Kilbirnie network. In terms of the design size of a decentralised battery, a 5 kW AC inverter can be paired with mostly 10 kW of PV panels supplying AC loads or exports to the grid (Standards New Zealand, 2025). In this study. The centralised battery size depends on the load's profile and how much of the battery can handle the stress of the transformer. The centralised BESS size is estimated from the transformer load profile by identifying the overload above the rated limit and the duration of the peak period. The required battery is based on the maximum peak reduction needed which is needed to be around 20-30% of its SOC at the end of the day.

3.2. Modelling and Tool Selection

All simulations are performed in DIgSILENT PowerFactory (version 2024). The network model represents a Wellington suburban LV feeder with a 500–1000 kVA transformer and 565 residential connection points. Transformer ratings and impedance data were provided by Wellington Electricity.

3.3. Scenario structure and dispatch strategies

The analysis is divided into four seasonal conditions (summer, autumn, winter and spring) to capture the variation in time in electricity demand and load behaviour. A multi-stage temporal framework is employed, with a base case (2025) and three stages of future development: short-term (2030), mid-term (2035), and long-term (2050). While all four seasons are considered to ensure completeness, the analysis primarily focuses on summer and winter scenarios to represent the most critical operating conditions. Winter is used to evaluate peak demand and maximum network loading driven by the coincidence of heating and lighting loads, while summer captures minimum demand conditions and potential impacts such as reduced loading or interactions with distributed generation (e.g., PV). This type of approach ensures that both very high and very low demand conditions are properly represented in the evaluation. Three progressive scenarios are developed to assess the technical potential of increasing DER integration:

1. **The current case (year 2025):** This period is the Base Case, with no DERs, representing the current state of the feeder with only existing household demand, adding EV load. Household Base Load (P load(t)) represents the baseline household electricity demand (kW) as a function of time. It is typically derived from measured load profiles and can be expressed as the aggregation of major end-uses:

$$P_{load}(t) = P_{hp}(t) + P_{hw}(t) + P_{light}(t) \quad (1)$$

Where:
Php(t): heat pump demand;
Phw(t): hot water demand; and
Plight(t): lighting demand.

In this study, EV charging is modelled as an additional residential load integrated into the base household demand. The EV load is treated as a time-dependent power demand, like other end-use loads, and is added directly to the existing load profile.

Base Case load (Net Household Demand Loads with EV loads [kW]):

$$P_{net}(t) = P_{load}(t) + P_{EV}(t) \quad (2)$$

$P_{EV}(t)$ represents the EV charging demand and is incorporated as a normal load addition without modifying the underlying household consumption structure. This approach assumes EV charging behaves as a conventional electrical load, contributing to overall demand and potentially increasing peak loading, particularly during periods of high coincidence with existing residential loads. The baseline feeder performance (without DER integration) is assessed using key operational indicators. They are defined as follows:
Busbar (Voltage magnitude [p.u]):

$$\Delta V(p.u) = \frac{V_{actual}}{V_{base}} \tag{3}$$

Line loading [%]:

$$Line\ loading(\%) = \frac{S_{actual}}{S_{rated}} \times 100\% \tag{4}$$

Transformer loading in percentage [%]

$$Transfomer\ loading(\%) = \frac{S_{transformer}}{S_{rated}} \times 100\% \tag{5}$$

2. **The future case (years 2030, 2035 and 2050):** These periods are the combination of Base, PV and BESS. In this study, the BESS is modelled as centralised and decentralised model. For the PV systems, they integrate at varied penetration levels (5%, 10%, 28% households for the year 2030, 2035 and 2050 respectively). The power generate by a rooftop PV system at each household node is modelled as a function of its installed capacity, local irradiance, and system efficiency. The generation active power output is given by:
PV power output [kW]:

$$P_{PV}(t) = P_{rated} \cdot \eta_{sys} \cdot \frac{G_{(t)}}{G_{STC}} \tag{6}$$

Net load with PV contribution [kW]:

$$P_{net}(t) = P_{load}(t) - P_{PV}(t) \tag{7}$$

3. From 2030 to 2050, as PV penetration grows, the community battery is expected to increase local self-sufficiency, decreasing the dependence of the area. Some of household-scale BESS are installed alongside PV, operated with peak-shaving control activated when transformer loading exceeded 90% of rated capacity. The control is added and set up by 3 levels of BESS capacities (e.g., small, medium, and large battery size, involving the Base + PV case). For the battery sizing rules, it depends on how much total energy the battery can store. In addition, power rating (kW) defines how fast it can charge or discharge. These two values determine how long the battery can run at full power.

$$Duration\ (hours) = \frac{Power\ rating\ (kW)}{Energy\ capacity\ (kWh)} \tag{8}$$

The size of the battery is also determined by the peak demand of the transformer with constant loads. Peak shaving with a small battery provides limited benefit. The practical design for network constraint management is a medium-balanced duration system. On the other hand, a large, longer discharge system has better peak shaving performance, but the cost is much higher.

Net load with PV and BESS [kW]:

$$P_{net}(t) = P_{load}(t) - P_{PV}(t) \pm P_{BESS}(t) \tag{9}$$

The hybrid dispatch algorithm prioritises charging BESS with surplus PV during midday, discharging during evening peaks (such as water heaters and EV chargers). Each scenario is run for a day in season using an hour time step, ensuring the capture of seasonal variation in solar resource and load behaviour.

3.4. Control framework

The control strategy is to solve the voltage stability for different PV generation and reduce the transformer peak loading by coordinating BESS charging using algorithms on:

- Feeder-level supervision control to measure feeder data.
- BESS controllers to respond to PV and transformer data to charge/discharge.
- QDSL in DIgSILENT PowerFactory with an hour resolution across the entire study year, capturing daily and seasonal variations.

- **Level supervision control**

The supervisor monitors the loading and voltages in real time and broadcasts vital system information to all the distributed controllers.

- Inputs: Bus voltage and transformer apparent power
- Output: Percentage of feeder loading, voltage range limits.
- Thresholds: Transformer loading trigger θtr=90% and Voltage range is between Vmin=0.95 and Vmax=1.05 p.u.

- **BESS for peak shaving control:**

  The BESS controller is a centralised and decentralised controller for transformer overloading and voltage fluctuation by time shifting energy by storing surplus solar generation during mid-day and discharging during evening demand peaks. This process, called peak-shaving, helps flatten the overall load profile at the low voltage level.

  The analysis considers three levels of PV penetration: 5%, 10% and 28%(Wellington Electricity 2025). These are considered progressive expansions of rooftop solar adoption for the years 2030, 2035 and 2025, respectively. Load and PV generated after running the base case, PV represent the actual energy demand. Similarly, several BESS capacities (X, Y, Z) are considered to investigate the effect of storage sizing on the network performance at each PV growth level presented in Table 2.

Table 2. Control peak shaving

Scenario	PV (%)	Year	Centralised and Decentralised battery	Objective / Focus
Case 1	5 %	2030	X (kWh)	Baseline community PV with small BESS
Case 2	10 %	2035	Y (kWh)	Medium PV expansion with medium BESS
Case 3	28 %	2050	Z (kWh)	High PV penetration with large BESS

This research identifies the suitable size of battery ensuring the technical security (which is larger than the medium one, around 10 %) and economy. Even if the case of the battery size is bigger than usual, there are also economic and resilient aspects to be considered by the energy management system. For example, if the peak shaving only consumes from 20% to 90% as load shifting or Time-of-Use (TOU) Arbitrage, defined as the SoC. This is to maximise tariff differences charged by drawing energy from the grid during Off-Peak (for the cheapest) hours during the night, which is not only from excess PV. Then, the stored energy can supply the facility's demand during On-Peak (most expensive) hours. To be more considered, each household-scale BESS operates mainly under a transformer-aware control rule in three rules:

- **Charging rule (PV):**
  When local PV output exceeds load demand, the surplus power charges the battery:

$$P_{BESS}(t) = -min(P_{BESS}^{max}, P_{PV}(t) - P_{load}(t)) \tag{10}$$

Where $P_{BESS}<0$ indicates charging, and $P_{BESS}^{max}$is the inverter power rating.

- **Discharging rsule (transformer):**
  When transformer loading rises above the threshold θ_{tr}, the BESS discharges to support the feeder:
  Discharging continues until the loading falls below θ_{tr} or the SoC reaches its lower limit.

- **Battery SoC dynamics:**
  SoC is the energy available in the battery at a given time expressed as a percentage of the total usable capacity. In simulation, the SoC is a variable for when and how much the BESS can charge/discharge. The BESS energy level evolves as follows:

$$\mathrm{SoC(t+1) = SoC(t) + \eta_c P_{BESS}^{-}(t)\Delta t - \frac{P_{BESS}^{+}(t)}{\eta_d}\Delta t} \tag{11}$$

Where:
P_{BESS}^{-}: charging power (kW, negative convention);
$P_{BESS}^{\mp}$: discharging power (kW, positive convention); and
ηc , ηd: charge and discharge efficiencies.

The controller constrains SoC from 20 to 90 % to protect battery life (Yu et al., 2016; Rahman and Alharbi, 2024). This ensures the BESS charges from solar surplus at midday and discharges during peak evening demand to reduce transformer loading. The battery control charge is related to the battery size.

4. Results and discussion

The main discussion focuses on the key simulation results for summer and winter conditions in 2025 and 2050. These years are used to show how increasing PV and EV uptake affecting transformer loading, line loading, and busbar voltage performance over time. The results are discussed by comparing two main scenarios: the reference case without BESS and the BESS integration case. The reference case represents the expected LV network performance when future demand is supplied only by the existing transformer and feeder infrastructure. The BESS integration case then evaluates how battery storage can reduce transformer loading, relieve feeder constraints, and improve voltage magnitude during peak operating periods. Although the main analysis focuses on

2025 and 2050, the 2030 scenario is also included to illustrate the battery sizing process and to show how the required BESS capacity changes as network stress increases. The main text presents the base case, and the long-term impacts. The supplementary document provides the detailed simulation results for the additional scenarios.

4.1. Reference case without BESS

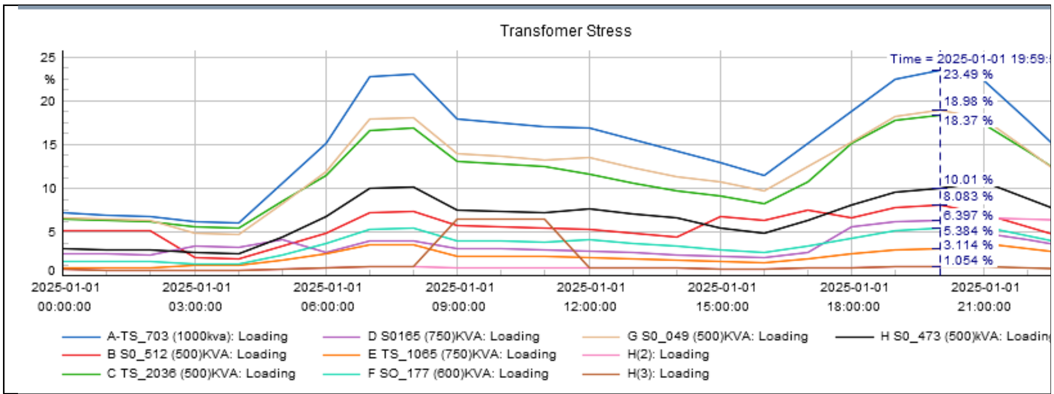
4.1.1. Transformer loading

The graph scenario illustrates the increase in transformer stress over time when EV charging is considered as an additional residential load, especially during the winter peak-demand periods. This section shows the effect of EV integration on transformer loading with the non-DER assumption. The results are assessed for summer/winter conditions for the 2025 base case and the 2050 long-term scenario.

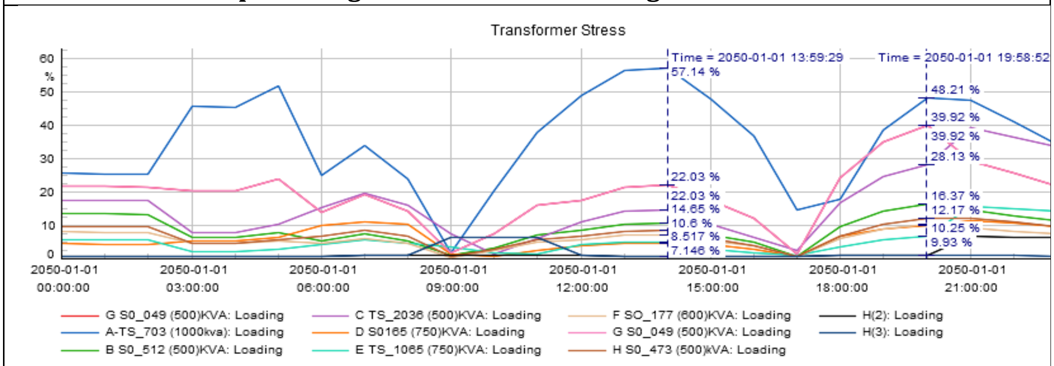
In Figure 6, the transformer loading in the 2025 base case is within acceptable operational limits for both seasons. Summer loading levels are relatively low, with peak values generally below 25% of rated capacity, and are representative of typical residential demand patterns with moderate diurnal variation. However, winter loading is much higher due to the overlapping of heating and lighting demand, and maximum values are near to 90%, which indicates the operation near the limits of transformer capacity during evening periods. In the 2050 scenario, the increase in EV uptake causes a significant increase in transformer loading in both seasons. In summer 2050, peak loading rises to around 55-60%, reflecting the growing impact of EV charging even at times of lower baseline demand. However, the most critical impact is observed in winter 2050, in which the transformer loading exceeds 100% and reaches about 135-140% at peak hours. This indicates that the summer conditions are still manageable, and the winter peak demand becomes a major constraint at high EV penetration.

4.1.2. Line loading

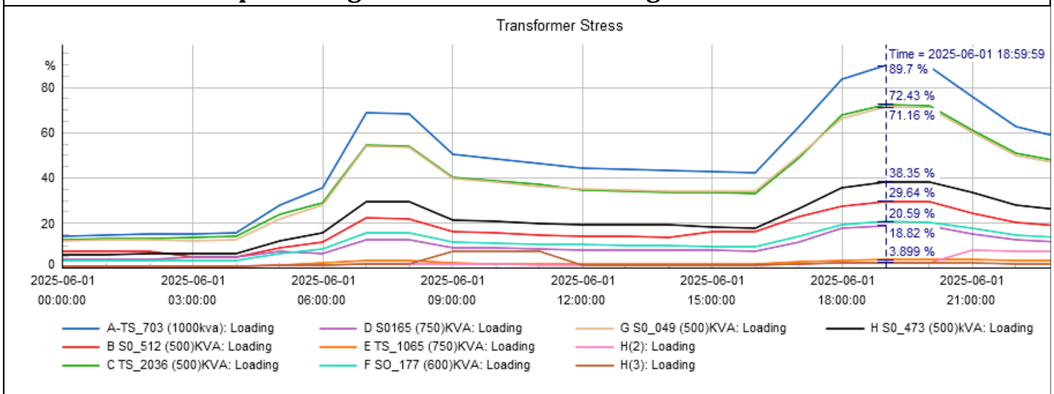
From the 2025 base case to 2050, it demonstrates an upward trend in line utilisation with system expansion and increased electrification. The intermediate stages (2030 and 2035), provided in the supplementary material, show a gradual transition in loading levels between these two extremes. Figure 7 illustrates the line loading at the transformer level for summer conditions under the 2025 base case and 2050 long-term scenario, demonstrating the effect of system expansion and increasing PV and EV penetration on network utilisation.



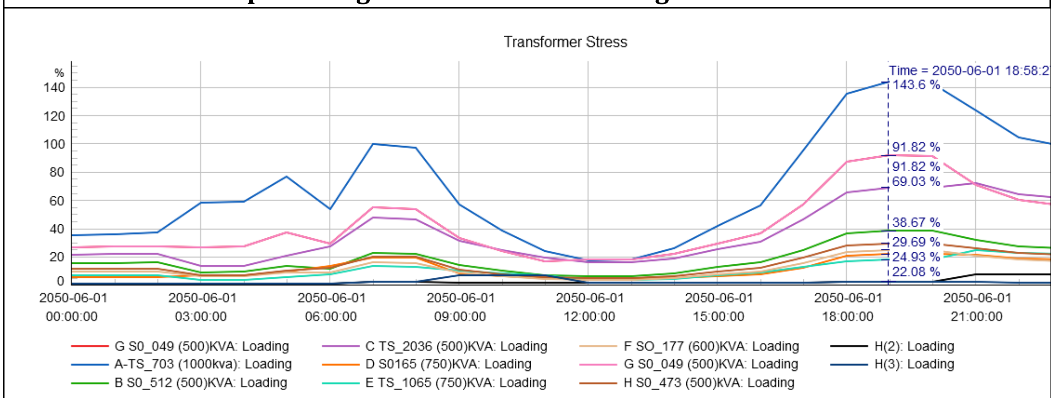
The percentage of transformer loading in Summer 2025



The percentage of transformer loading in Summer 2050

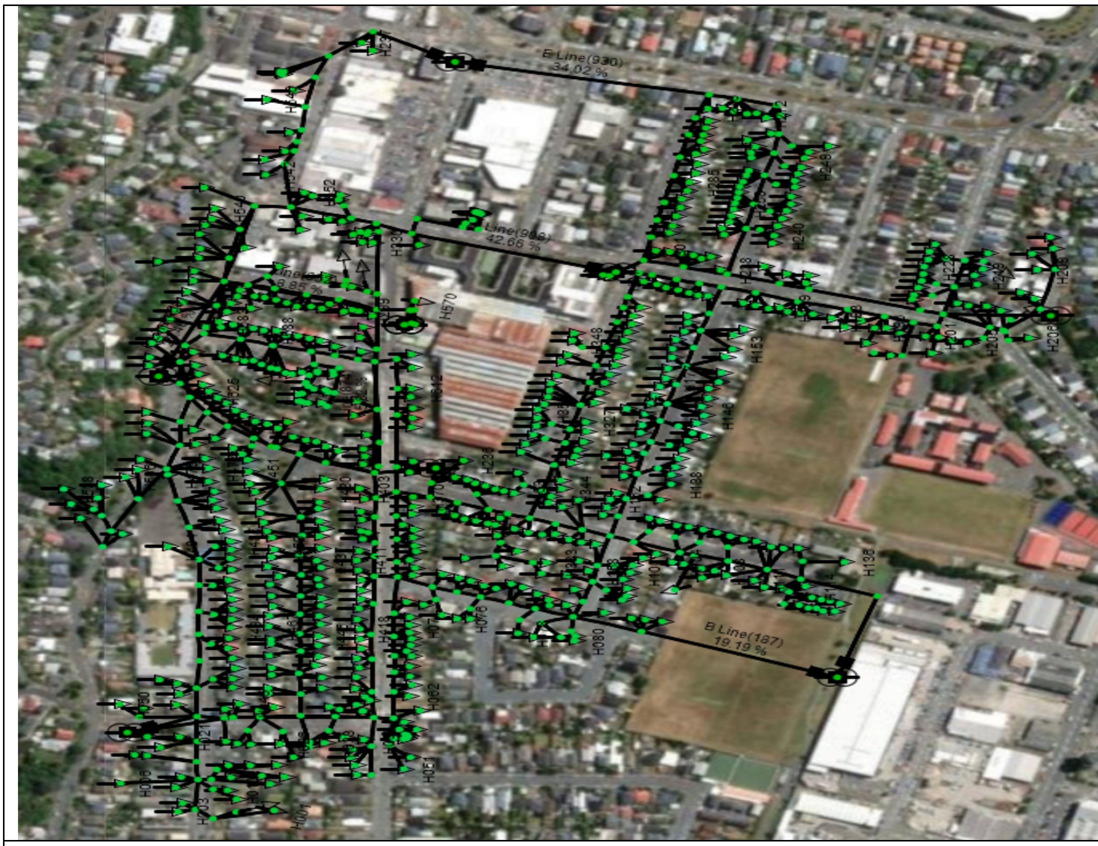


The percentage of transformer loading in Winter 2025



The percentage of transformer loading in Winter 2050

Figure 6. The percentage of transformer loading in Summer and Winter in 2025 and 2050



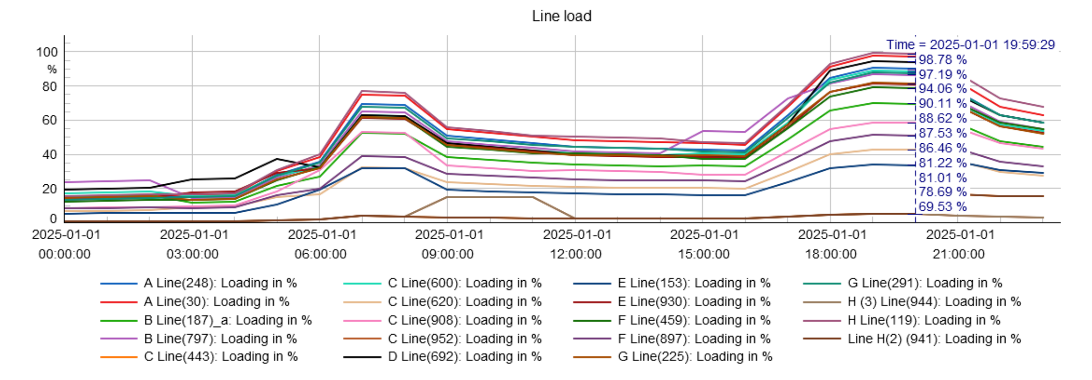
Line stress in Summer 2025

Line stress in Summer 2050

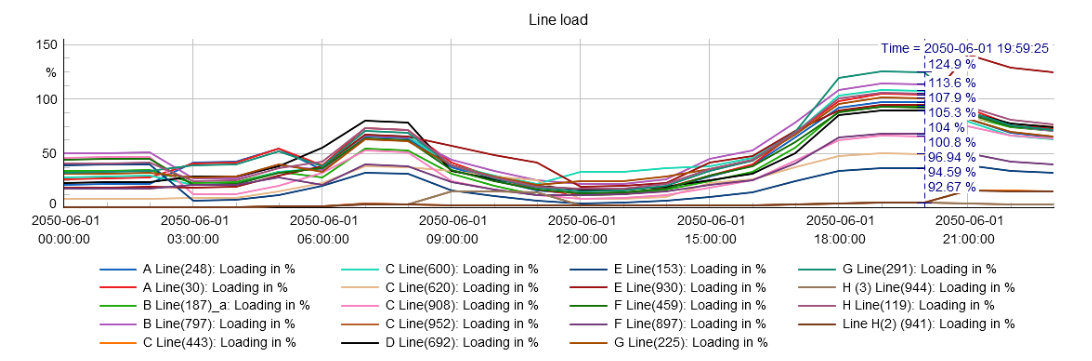
Figure 3. Comparison of line stress in Summer between the year 2025 and 2050

Figure 7 shows the summer line loading comparison for the 2025 base case and the 2050 long-term scenario. In summer 2025, the feeder operates below 30%, with the highest loading on E Line (930) at around 34% in the evening. Other lines - A Line, B Line, C Line and G Line - also see increased use in 2050 compared with 2025, particularly in the midday and evening periods. But all lines remain below the 100% thermal limit, which indicates that summer conditions result in increased network utilisation, but not in critical overloading.

Figure 8 compares winter line loading between the 2025 and the 2050 long-term scenarios. In winter 2025, the line utilisation is already high, with several feeders reaching close to or above their rated limits during the evening peak. The maximum loading reaches approximately 98%, indicating that some line sections are already under stress during winter peak demand. By winter 2050, the loading increases further, with several feeders exceeding the 100% thermal limit, and the highest values reaching approximately 140% for E Line (930) and 120% for G Line (291). Lines such as B Line, E Line, G Line, and H Line show a high utilisation during the evening period above 100%. This confirms that winter is the critical season for line stress and future EV charging demand growth.

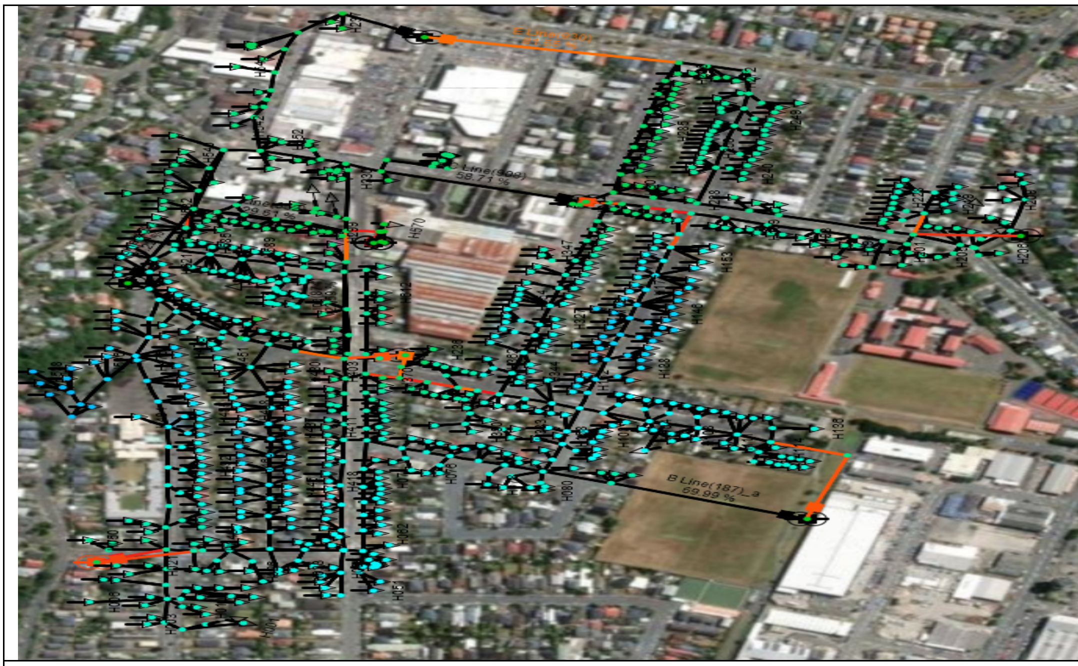


The percentage of Line loading in Winter 2025



The percentage of Line loading in Winter 2050

Figure 8. The percentage of line loading in Winter 2025 and 2050



Line stress in Winter 2025

Line stress in Winter 2050

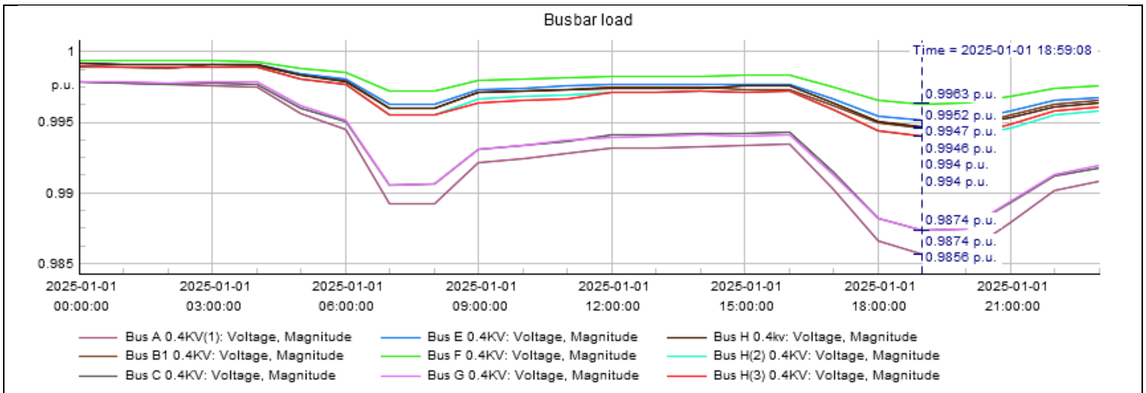
Figure 4. Comparing Line stress condition in Winter

Figure 9 demonstrates the location distribution of line stress for summer and winter in 2025 and 2050. For summer 2025, most lines are within safe limits. Winter 2025 shows higher stress along main feeder routes and residential areas with increased seasonal demand.

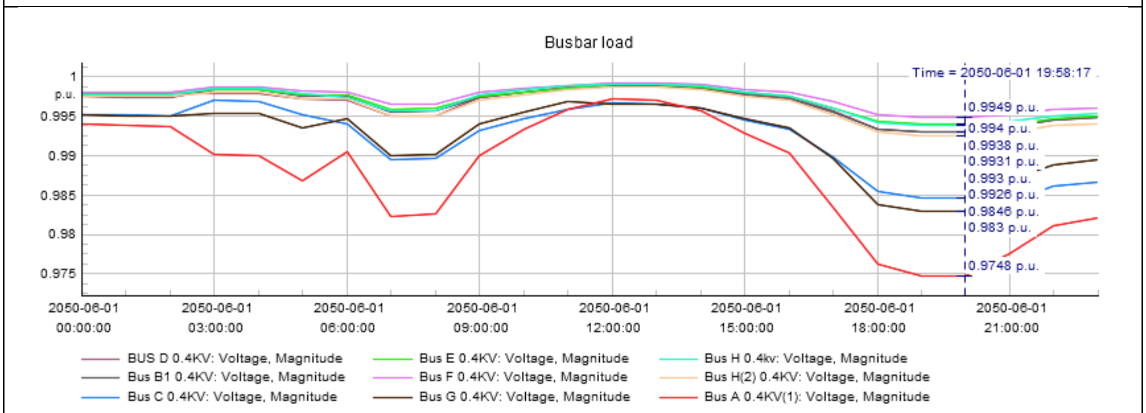
The increase in line stress is more significant by 2050, especially in winter, with several sections experiencing high loading. Some areas improve after adding battery storage, showing that BESS helps reduce local line stress. However, the most critical case is winter 2050, where it is shown that battery support improves the network performance but does not remove all constraints in line loading.

4.1.3. Busbar

In the summer case of 2025, busbar voltages are still near 1.0 p.u. with only minor voltage drops in the morning and evening demand periods. The minimum voltage is still about 0.996 p.u., which indicates stable operation and sufficient voltage support for the base-case loading condition. By summer 2050, the voltage deviations will become more noticeable due to higher demand and EV penetration. The minimum voltage on several busbars drops deeper during peak periods, reaching approximately 0.986–0.988 p.u. The larger variation, even though still within acceptable operating limits, implies that the voltage is still stable.



Voltage magnitude in Winter 2025



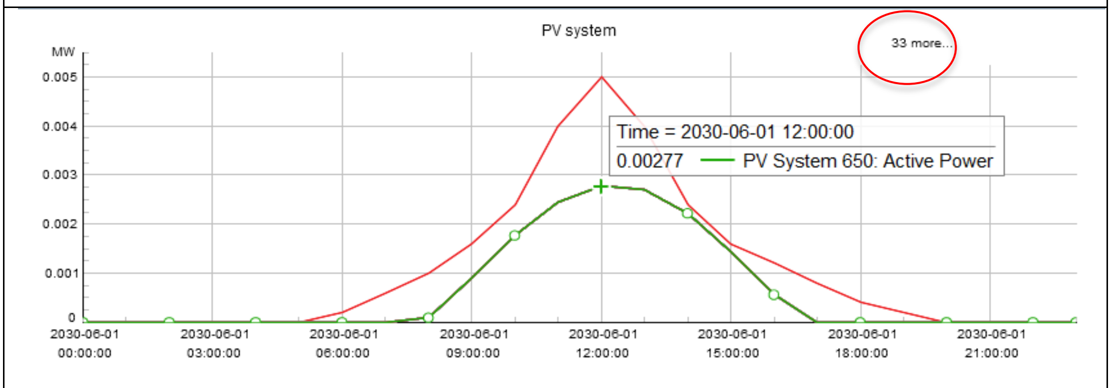
Voltage magnitude without the centralised battery in Winter 2050

Figure 5. Voltage magnitude in Winter 2025 and 2050

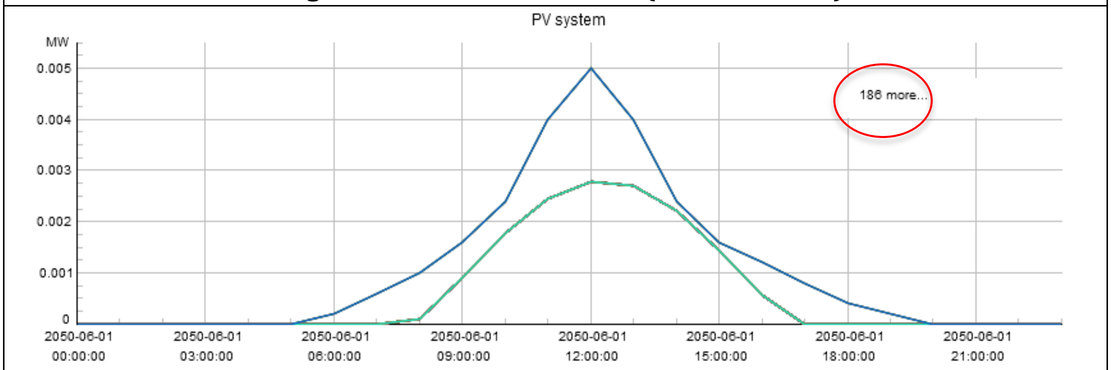
Figure 10 presents the busbar voltage magnitude in 2025, and 2050 (with and without the centralised battery) for winter. In the winter case of 2025, the voltage is relatively stable and close to 1.0 p.u., but visible voltage drops are observed at morning and evening demand peaks. The minimum voltage is approximately 0.986 p.u. Thus, the system is still within acceptable, but already subject to a higher voltage variation than in the summer case. Without the centralised battery in the 2050 winter scenario, the voltage drop is critical due to increased EV penetration. The minimum voltage occurs around the evening peak with Bus A 0.4 kV dropping to under 0.9748p.u. That means that the 2050 winter is the most stressful for voltage from EV charging, heating and lighting demand.

4.1.4. Solar photovoltaics

The PV system in the study is modelled as a 5kW residential PV system, which is consistent with the common capacities of rooftop PV systems. In summer (2030 and 2050), the PV highest output is about 0.005 MW (5 kW), around 31.043 KWh/day with a longer generation period, showing higher irradiance and longer daylight hours. In contrast, Winter in both 2030 and 2050 has a lower peak 0.003 MW (3kW), around 11.49 KWh/day and a shorter generation window due to lower solar power availability (see Figure 11). For summer, the year 2030 contains 33 households generating around 31.043 KWh and the year 2050 contains 186 households generating around 190,541.934 KWh. For Winter, the year 2030 contains 33 households generating around 379.203 KWh and the year 2050 contains 186 households generating around 70531.758 KWh. Results show that the seasonal variation has a strong effect on the PV output, with higher and more sustained generation in summer than in winter.



PV generation in Winter, 2030 (33 households)



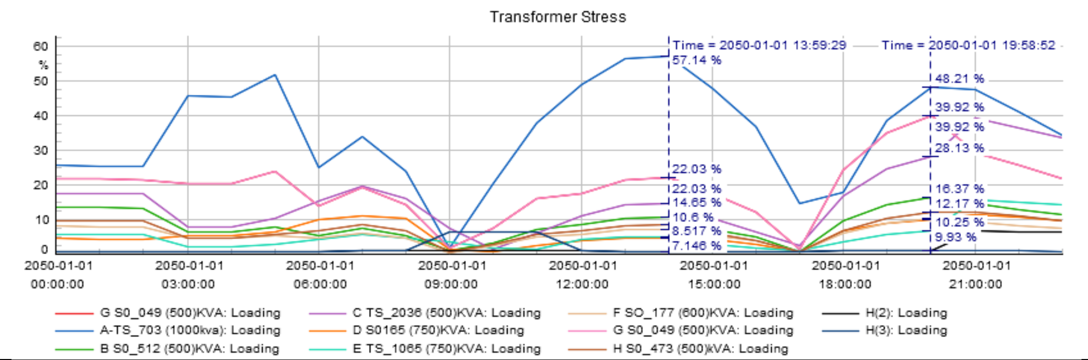
PV generation in Winter, 2050 (186 households)

Figure 6. PV generation in Winter, 2025 and 2050

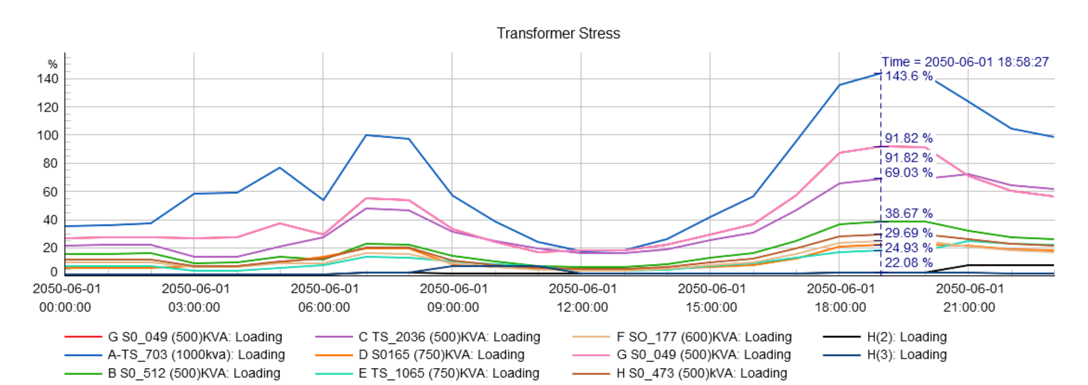
4.2. BESS integration case

4.2.1. Battery impacts on the transformer

Figure 12 indicates the year 2050 situation for summer and winter. In the summer 2050 case, transformer loading remains within acceptable operational limits throughout the day. Even if there is an increase in the EV loads, the peak remains below the rated transformer capacity by approximately 57%. In contrast, the winter 2050 case shows a higher loading profile. The A-TS_703 transformer reaches around 143% during the evening peak, while another transformer approaches 94%.



Transformer loading without battery in Summer 2050



Transformer loading without battery in Winter 2050

Figure 7. Transformer loading without battery in Summer and Winter 2050

Figure 13 presents the effect of different BESS sizes on transformer loading under winter operating conditions. In the 2030 winter case, the peak loading of transformer A-TS_703 reduces from 125.3% to 91% by applying a 3.5 MWh battery. This indicates that, in 2030, the selected battery capacity can support the network and reduce transformer stress. In the 2050 winter case without battery control, transformer loading increases substantially, with A-TS_703 reaching approximately 143%. With the 4MWh, it can reduce the transformer stress from 143% to around 108%. However, increasing the battery size from 4 MWh to 5 MWh shows that the peak transformer loading shares the same loading stress approximately 108% by the same controller.

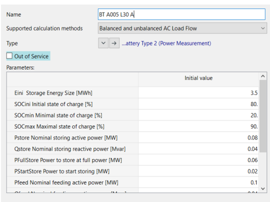
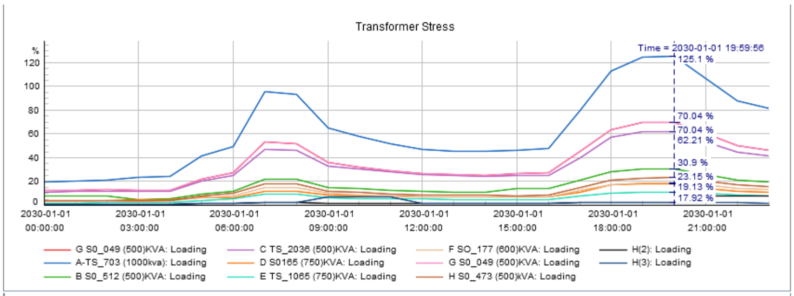
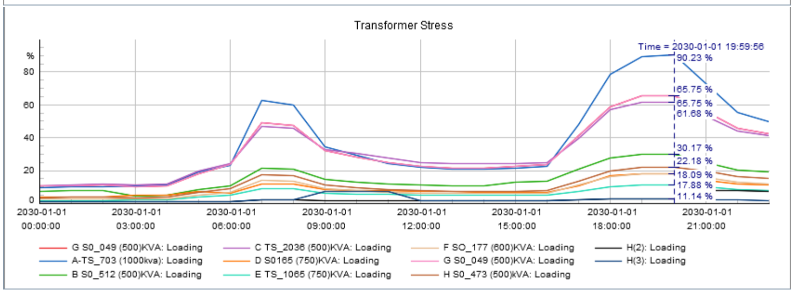
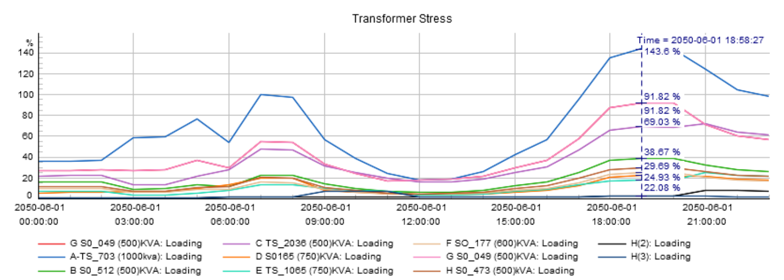
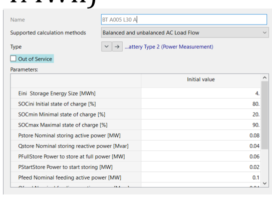
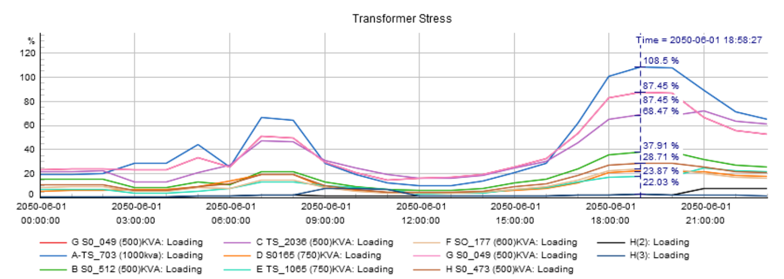
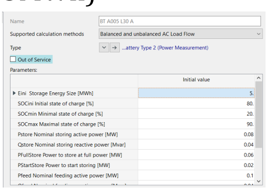
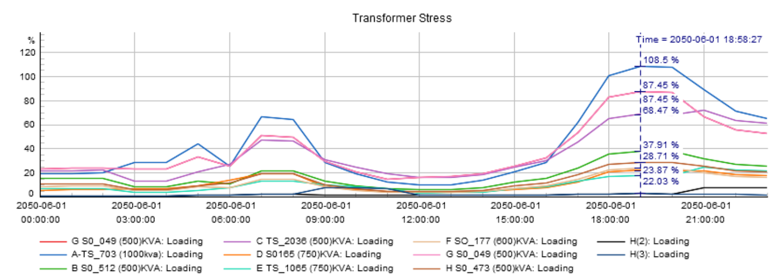
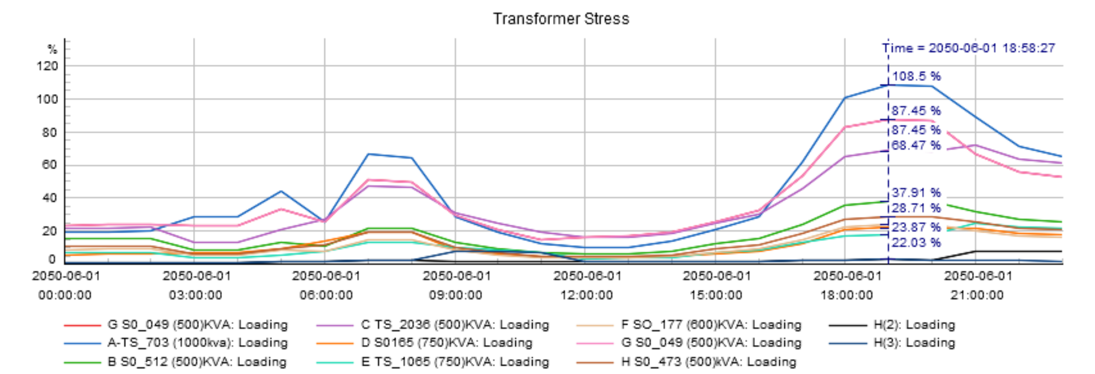
Battery Controlled	Transformer Stress
2030 (Winter 3.5 MWh) 	 
2050 (Winter No battery)	
2050 (Winter 4MWh) 	
2050 (Winter 5MWh) 	

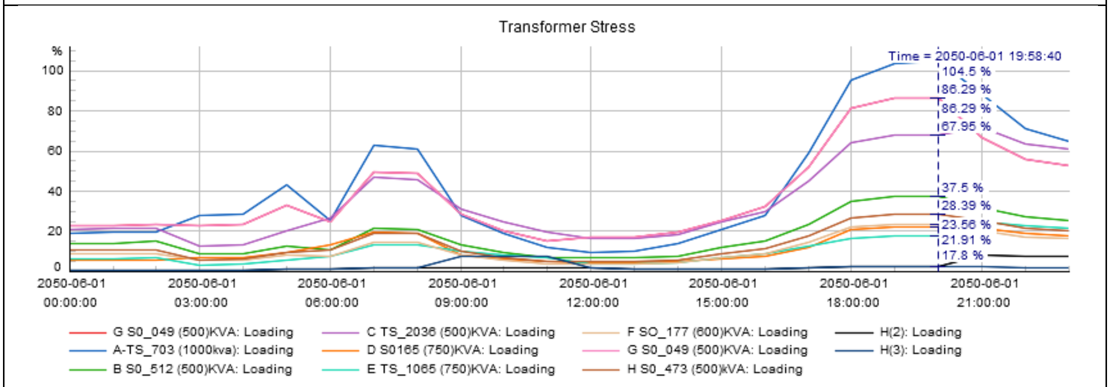
Figure 8. Battery size impact on transformer stress in 2030 and 2050

Figure 14 compares transformer loading in the winter 2050 scenario after applying centralised and decentralised BESS configurations. Under the centralised BESS scenario, the maximum loading of transformer A-TS_703 decreases from 143% to approximately 108%, while transformer G SO_049 increases from 93.85% to 89.35%. Adding the decentralised BESS scenario, it provides further improvement with the peak loading of A-

TS_703 reduced to approximately 104%, and G SO_049 reduced to about 88%. Even though the transformer A-TS_703 exceeds 104%, it takes only one hour from 18:30 to 19:30. This demonstrates that centralised battery combining decentralised BESS can mitigate transformer stress in 2050.



Transformer loading with only a centralised battery in Winter 2050



Transformer loading with both centralised and decentralised battery in Winter 2050

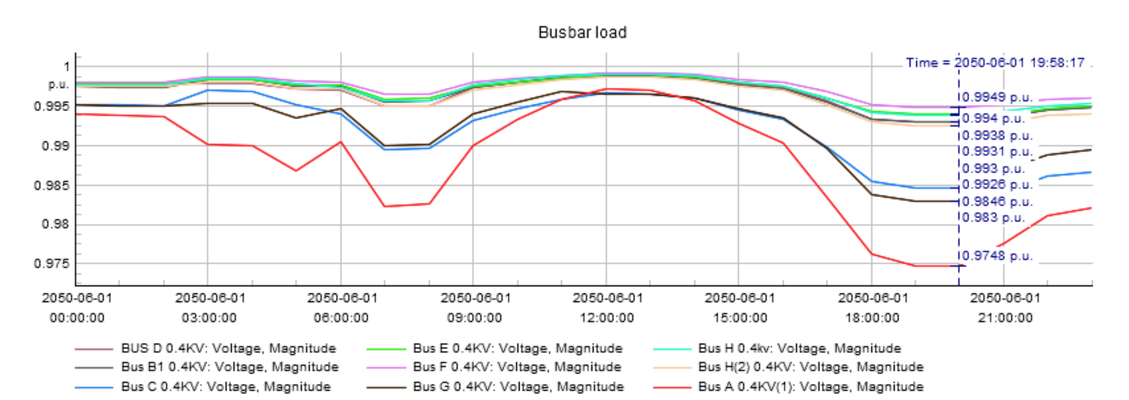
Figure 9. Transformer loading with the centralised battery, and the centralised with decentralised battery in Winter 2050

4.2.2. Battery impacts on busbar

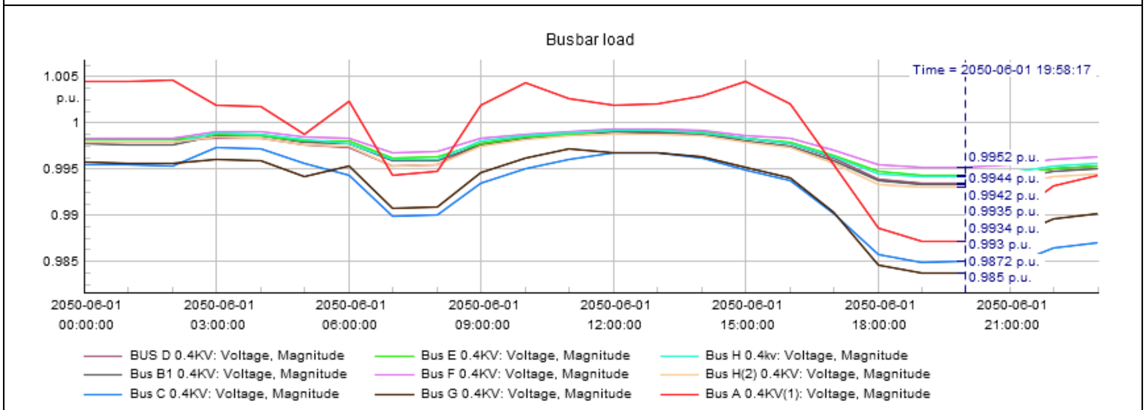
Figure 15 compares the busbar voltage magnitude in the 2050 winter scenario under three conditions: without battery support, with a centralised battery, and with combined centralised and decentralised batteries. In the case without battery support, the voltage profile shows a significant drop during the evening peak. The lowest voltage occurs at Bus A 0.4 kV, falling to approximately 0.9748 p.u.

When the centralised battery is applied, the voltage profile improves noticeably. The minimum voltage increases from around 0.9748 p.u. to 0.985 p.u., showing that the centralised battery can provide effective voltage support during the evening peak. However, some busbars still experience visible voltage drops, indicating that centralised support mainly reduces transformer-level stress but may not fully address local feeder-level voltage variation.

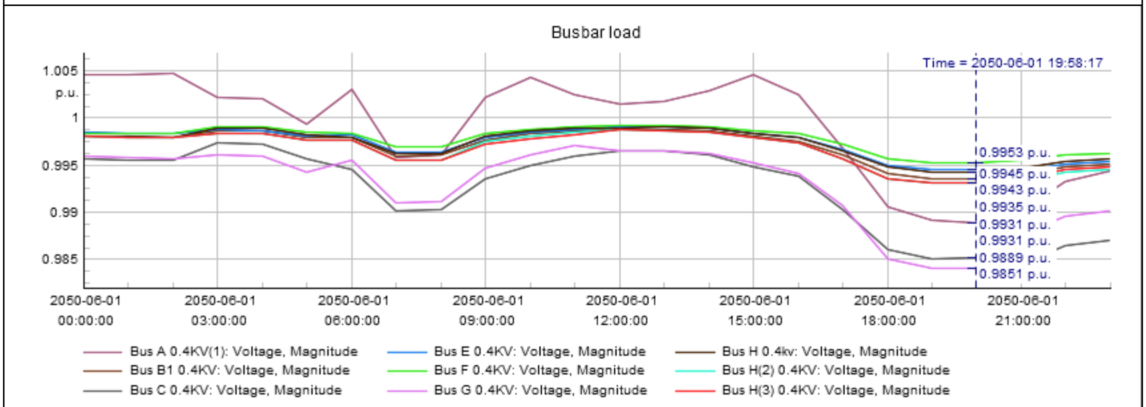
With the combined centralised and decentralised battery configuration, the voltage profile becomes more balanced across the LV network. The lowest voltage remains around 0.9851 p.u., but several busbars are maintained closer to 0.993–0.995 p.u. during the evening peak. This suggests that decentralised batteries provide additional local support closer to the load, helping to reduce feeder-level voltage drops.



Voltage magnitude without the centralised battery in the Winter 2050



Voltage magnitude with the centralised battery in the Winter 2050

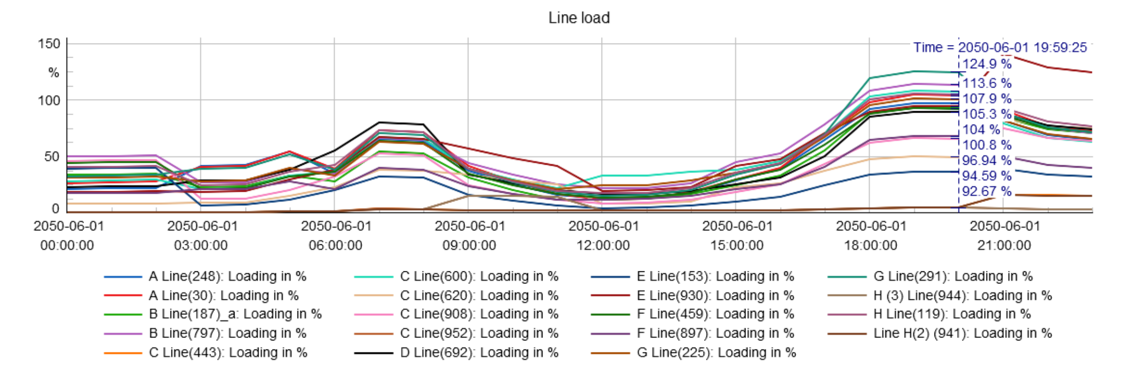


Voltage magnitude with the centralised and decentralised battery in the Winter 2050

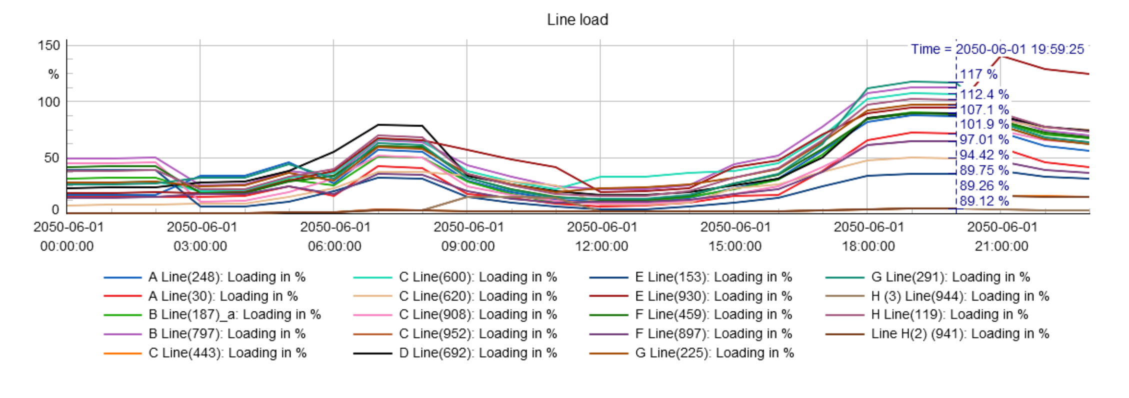
Figure 10. Comparison voltage magnitude with no battery, the centralised and decentralised battery in the Winter 2050

4.2.3. Battery impacts on line loading

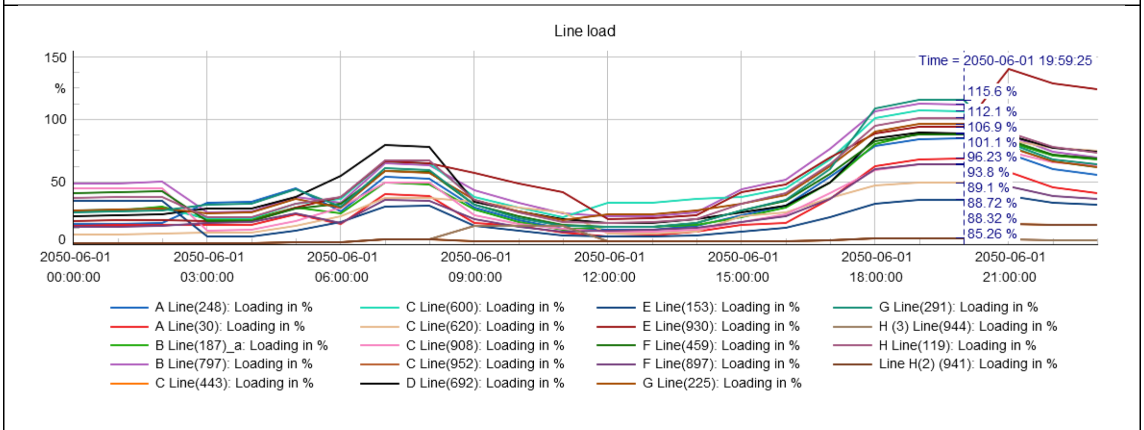
Figure 16 compares the line loading in the 2050 winter case under three scenarios: without battery, with a centralised battery, and with combined centralised and decentralised batteries. In the without-battery case, the line loading increases during the evening approximately 124.9%. Several other lines also exceed 100%. This means the winter 2050 demand profile creates significant feeder stress. After applying the centralised battery, the line loading is reduced to around 117%. In Figure 17, however, some lines still remain above their rated limits, which means that centralised storage alone cannot fully remove local feeder constraints. With the combined centralised and decentralised battery configuration, the line loading is reduced slightly further, with the highest loading decreasing to around 115.6%.



Line loading without battery in the Winter 2050



Line loading with the centralised battery in the Winter 2050



Line loading with the centralised and decentralised battery in the Winter 2050

Figure 11. Comparison of line loading with only the centralised, and both the centralised and decentralised battery in the Winter 2050

Line Mapping without battery in the Winter 2050

Line Mapping with only the centralised battery in the Winter 2050

Line Mapping with the centralised and decentralised battery in the Winter 2050

Figure 12. Comparison of line Mmpping with only the centralised, and both the centralised and decentralised battery in the Winter 2050

4.3. Discussion

4.3.1. EV load impact without PV and BESS

EV charging load increases transformer and line loading. In summer 2025, transformer loading is below 25%, while winter 2025 reaches approximately 90% due to the combination of heating, lighting, and general residential demand. However, by 2050, an increase in EV creates a stronger impact. Summer transformer loading increases to about 55–60%, while winter load reaches around 140%. Overall, in summer, the existing transformer capacity is sufficient and no transformer replacement or upgrade is required. However, due to the winter heating demand, lighting demand, and additional EV charging load, there is a significant overload in the transformer in the winter.

4.3.2. Line loading

Line loading results show an increasing trend from 2025 to 2050. It expects most lines to run well below 30-35% of rated capacity in Summer 2025, so there will be lots of network capacity available. The line loading in winter 2025 is increased by about 90-100%, indicating that the network is close to its limit during the winter peak. By 2050, line loading increases further across the network. The summer 2050 is still largely controllable at peak queue loading of around 60-70%. However, in the winter of 2050, several lines will exceed 100% and reach critical levels of about 110-120%. This shows that the centralised battery helps reduce the overall loading during the evening peak by supplying power at the transformer level. Some lines remain above their rated limits, which means that centralised storage alone cannot fully remove local feeder constraints. With the combined centralised and decentralised battery configuration, the line loading is drop slightly.

In addition, the most considerable line is E line (930) which will reach around 140%. The decentralised batteries provide additional local support by reducing demand on specific feeders closer to the load. Although this configuration improves the line loading profile compared with the centralised-only case, some lines remain overloaded. Therefore, the results suggest that coordinated BESS control can reduce feeder stress, but selective line upgrades may still be required at the most constrained locations.

4.3.3. Busbar

The results of the busbar in voltage magnitude show that the network remains within the acceptable voltage limits in all cases, but the voltage magnitude decreases from 2025 to 2050. In summer 2025, the busbar voltages are close to 1.0 p.u. with a minimum of about 0.996 p.u., which indicates a stable operation. In summer 2050, the minimum voltage values are around 0.986–0.988 p.u., due to higher demand and EV penetration, resulting in deeper voltage drops. In the 2050 winter case without the centralised battery, the voltage drop becomes more problematic due to increased electricity demand and higher EV penetration. The lowest voltage occurs around the evening peak, where Bus A 0.4 kV falls to approximately 0.9748 p.u. This shows that the 2050 winter scenario creates the most stressful voltage condition, mainly due to the combined impact of EV charging, heating, and lighting demand. After the centralised battery is added, the minimum voltage at Bus A 0.4 kV increases from 0.9748 p.u. to approximately 0.985 p.u. This improvement indicates that the battery helps mitigate the voltage drop and improves voltage support during the winter peak period.

4.3.4. PV contribution to the system

The PV system is modelled as a residential system with a peak power of 5 kW. The PV profile is typical of daily generation with an increase in the morning, a peak in the midday and a decrease in the afternoon. In summer, the PV output is around 5 kW, and the generation period is longer due to increased irradiance and daylight hours. On the other hand, the maximum winter PV output is about 3 kW with shorter generation. This means that PV can meet the demand during the day, especially in summer, but its contribution is limited during the winter evening peaks, when the transformer is most stressed. Thus, PV is good for reducing daytime net demand but cannot solve winter evening overloading problems without a battery in 2050.

4.3.5. Battery control and size for peak shaving

The size of the BESS is an important factor in reducing transformer stress, since it can be discharged during high-demand periods. For example, in the 2030 winter scenario, the peak loading of transformer A-TS_703 is reduced from 125.3% to 91% by applying a 3.5 MWh battery. For the 2050 winter scenario, the transformer loading increases substantially without battery control, and A-TS_703 reaches around 143%. The peak loading drops to about 108% with the introduction of a 4 MWh battery. A 5 MWh battery has the same reduced value at 108% with the same control. This means that without any modification of the controller, transformer overloading cannot be completely solved by increasing battery capacity. In 2050, the transformer is still slightly overloaded for an hour, but the battery still provides a meaningful reduction in stress and improves the network's capacity to cope with future demand growth.

4.3.6. Battery ownership

The centralised BESS reduces transformer loading significantly in the winter 2050 case. Without adding the BESS, the most stressed transformer reaches approximately 143%. After applying centralised BESS, the peak loading of transformer A-TS_703 decreases to approximately 108%, while transformer G SO_049 reaches around 89%. This demonstrates that centralised BESS is effective in reducing peak transformer stress, especially during the evening demand period. By adding decentralised BESS, it can reduce the loading of A-TS_703 further from approximately 108% to about 104%, while G SO_049 decreases from around 89% to about 88%. In the centralised-only case, battery output drops to about 0.04 MW before rising to 0.09–0.10 MW. With decentralised support, the centralised battery output remains around 0.06 MW. This shows that decentralised batteries can assist the centralised BESS by supporting the local feeder and reducing the burden on the main battery. Under the combined centralised and decentralised configuration, the centralised battery remains the main source of support, while decentralised batteries provide smaller local injections and absorptions. This distributed operation improves local balancing, reduces feeder stress, and helps reduce the centralised battery burden.

4.4. Limitation

This work is limited to one low-voltage feeder in Wellington. The work is modelled in DIgSILENT PowerFactory with a geographical reference and hourly simulations for one year. This resolution is suitable for annual planning and transformer utilisation analysis, but does not capture short-term dynamics such as voltage flicker, frequency events, or fast PV variations. Therefore, dynamic network stresses may be under-represented. The analysis focuses on rooftop PV and household-scale BESS, assessed mainly through transformer loading and voltage deviation. While the feeder is assumed to be representative of a Wellington case, variations in topology, transformer age, conductor size, and load diversity mean that the results are indicative rather than site specific. Moreover, BESS degradation is simplified by employing standard efficiency, depth-of-discharge limits and linear capacity fade, rather than detailed electrochemical modelling.

5. Conclusion

The study demonstrates a significant increase in transformer and line loading due to the adoption of EVs, especially during winter peak periods. Without PV and BESS, or under DER conditions, the network is within acceptable limits in 2025, but in 2050 the transformer loading in winter reaches around 135–140%, with evident overloading. With several feeders being loaded above their rated capacity during the winter, the queue loading increases. This confirms winter as the critical operating scenario due to the coincidence of EV charging, heating, lighting, and general residential demand. PV generation improves the network performance during the day, especially in summer, but its contribution is limited during the winter evening peaks.

5.1. Recommendations

The results of this study show that future LV distribution networks will require a more coordinated planning approach as electricity demand, PV generation, and EV charging continue to increase. Transformer and feeder stress are not only influenced by total demand growth, but also by the timing of demand, the location of DERs, and the way BESS is controlled. Therefore, network planning should consider both technical performance and operation, rather than relying only on conventional reinforcement. Based on the simulation outcomes, BESS can reduce transformer loading and improve network operation, but its effectiveness depends on correct sizing, placement, and coordination with PV and EV demand. Therefore, the following recommendations are made:

- Future planning should be based on winter peak-demand conditions, which are the most demanding on the transformer and feeder lines.
- A coordinated BESS strategy should be adopted that combines centralised storage for support at the transformer level and decentralised storage for local feeder relief.
- PV should be coupled with BESS to shift generation from daytime to the evening peak period.
- Consideration should also be given to coordinated EV charging to reduce the peak coincidence.
- Finally, selective transformer or feeder upgrades may still be needed at constrained locations where loading remains above rated limits after BESS support.

References

Abdalla AA, Moursi MSE, El-Fouly TH, Hosani KHA, 2023. A novel adaptive power smoothing approach for PV power plant with hybrid energy storage system. IEEE Transactions on Sustainable Energy, 14 (3), 1457–73, doi:10.1109/TSTE.2023.3236634.

Ahmed M, Ganeshan A, Moradi Amani AM, Al Khafaf N., Nutkani IU, Vahidnia A, Jalili M, Hasan K, Datta M, Razzaghi R, 2022. Effects of household battery systems on LV residential feeder voltage management. IEEE Transactions on Power Delivery, 37 (6), 5325–36, doi:10.1109/TPWRD.2022.3176099.

Al-Saffar M, Musilek P, 2020. Reinforcement learning-based distributed BESS management for mitigating overvoltage issues in systems with high PV penetration. IEEE Transactions on Smart Grids, 11 (4), 2980–94, doi:10.1109/TSG.2020.2972208.

Anderson B, Eyers D, Ford R, Giraldo Ocampo D, Peniamina R, Stephenson J, Suomalainen K, Wilcocks L, Jack M, 2018. New Zealand grid household electricity demand study 2014-2018. UK data service, doi:10.5255/UKDA-SN-853334.

Boston Consulting Group, 2022. The-future-is-electric-appendix-1-context-of-New-Zealands-electricity-sector. Accessed 19 August 2025 from: https://web-assets.bcg.com/3c/0b/6d23a6804ff985ff0ac9ecb7fc6d/the-future-is-electric-appendix-1-context-of-new-zealands-electricity-sector.pdf.

Chen T, Li M, Bae J, 2024. Recent Advances in lithium iron phosphate battery technology: A comprehensive review. Batteries, 10 (12), 424, doi:10.3390/batteries10120424.

Datta U, Kalam A, Shi J, 2020. Smart control of BESS in PV integrated EV charging station for reducing transformer overloading and providing battery-to-grid Service. Energy Storage, 28, 101224, doi:10.1016/j.est.2020.101224.

Datta U, Kalam A, Shi J, 2021. A review of key functionalities of battery energy storage system in renewable energy integrated power systems. Energy Storage, 3:e224, doi:10.1002/est2.224.

Fachrizal R, Ramadhani UH, Munkhammar J, Widén J, 2021. Combined PV–EV hosting capacity assessment for a residential LV distribution grid with smart EV charging and PV curtailment. Sustainable Energy, Grids and Networks, 26, 100445, doi:10.1016/j.segan.2021.100445.

Filho RD, Monteiro ACM, Costa T, Vasconcelos A, Rode AC, Marinho M, 2023. Strategic guidelines for battery energy storage system deployment: Regulatory framework, incentives, and market planning. Energies, 16 (21), 7272, doi:10.3390/en16217272.

Gailani A, Crosbie T, Al-Greer M, Short M, Dawood N, 2020a. On the role of regulatory policy on the business case for energy storage in both EU and UK energy systems: Barriers and enablers. Energies, 13 (5), 1080, doi:10.3390/en13051080.

Gailani A, Mokidm R., El-Dalahmeh, Mo'ath, El-Dalahmeh, Ma'd, Al-Greer M, 2020b. Analysis of lithium-ion battery cells degradation based on different manufacturers. 55th International Universities Power Engineering Conference (UPEC), doi:10.1109/UPEC49904.2020.9209759.

Garttan G, Alahakoon S, Emami K, Jayasinghe SG, 2025. Battery energy storage systems: Energy market review, challenges, and opportunities in frequency control ancillary services. Energies, 18 (15), 4174, doi:10.3390/en18154174.

Gerini F, Zuo Y, Gupta R, Vagnoni E, Cherkaoui R, Paolone M, 2021. Optimal grid-forming control of battery energy storage systems providing multiple services: modelling and experimental Validation. Preprint, arXiv, doi:10.48550/arXiv.2110.10052.

Gholami, M, Muyeen, SM, Abokhamis MS, 2024. Optimal sizing of battery energy storage systems and reliability analysis under diverse regulatory frameworks in microgrids. Energy Strategy Reviews, 51, 101255, doi:10.1016/j.esr.2023.101255.

Gouveia, J, Moreira CL, Lopes JAP, 2021. Rule-based adaptive control strategy for grid forming inverters in islanded power systems for improving frequency stability. Electric Power Systems Research 197, 107339, doi:10.1016/j.epsr.2021.107339.

Gui F, Chen H, Zhao X, Pan P, Xin C, Jiang X, 2024. Enhancing economic efficiency: Analyzing transformer life-cycle costs in power grids. Energies, 17 (3), 606, doi:10.3390/en17030606.

Guo Y, Zhang Q, Wang Z, 2021. Cooperative peak shaving and voltage regulation in unbalanced distribution feeders. IEEE Transactions on Power Systems, 36 (6), 5235–44, doi:10.1109/TPWRS.2021.3069781.

Jamroen C, 2022. The effect of SoC management on economic performance for battery energy storage system in providing voltage regulation in distribution networks. Electric Power Systems Research, 211, 108340, doi:10.1016/j.epsr.2022.108340.

Jawad A., Nahid-Al-Masood, Munim S, 2021. Optimal sizing of BESS for attaining frequency stability under high PV penetration. International Conference on Technology and Policy in Energy and Electric Power (ICT-PEP), doi:10.1109/ICT-PEP53949.2021.9601074.

Kamana-Williams B, Bishop D, Hooper G, Chase JG, 2024. Driving change: electric vehicle charging behavior and peak loading. Renewable and Sustainable Energy Reviews, 189, 113953, doi:10.1016/j.rser.2023.113953.

Karmakar S, Singh B, 2021. Battery energy storage (BES) for mitigation of short-term power fluctuations in large-scale solar PV plant due to cloud movement. 3rd International Conference on Energy, Power and Environment, doi:10.1109/ICEPE50861.2021.9404468.

Kim SH, Shin YJ, 2023. Optimize the operating range for improving the cycle life of battery energy storage systems under uncertainty by managing the depth of discharge. Energy Storage, 73, 109144, doi:10.1016/j.est.2023.109144.

Kryonidis GC, Kontis EO, Papadopoulos TA, Pippi KD, Nousdilis AI, Barzegkar-Ntovom GA, Boubaris AD, Papanikolaou NP, 2021. Ancillary services in active distribution networks: A review of technological trends from operational and online analysis perspective. Renewable and Sustainable Energy Reviews, 147, 111198, doi:10.1016/j.rser.2021.111198.

Kumar C, Lakshmanan M, Jaisiva S, Prabaakaran K, Barua S, Fayek HH, 2023. Reactive power control in renewable rich power grids: A literature review. IET Renewable Power Generation, 17 (5), 1302-1327, doi:10.1049/rpg2.12674.

Kumar NM, Chand AA, Malvoni M, Prasad KA, Mamun KA, Islam FR, Chopra SS, 2020. Distributed energy resources and the application of AI, IoT, and blockchain in smart grids. Energies, 13 (21), 5739, doi:10.3390/en13215739.

Lappalainen K, Valkealahti S, 2022. Sizing of energy storage systems for ramp rate control of photovoltaic strings. Renewable Energy, 196, 1366–75, doi: 10.1016/j.renene.2022.07.069.

Laws ND, Webber ME, Chen D, 2024. Valuing distributed energy resources for non-wires alternatives. Electric Power Systems Research, 234, 110521, doi: 10.1016/j.epsr.2024.110521.

Lin Y, Chen YW, Yang JT, 2023. Optimized thermal management of a battery energy-storage system (BESS) inspired by air-cooling inefficiency factor of data centers. International Journal of Heat and Mass Transfer, 200, 123388, doi:10.1016/j.ijheatmasstransfer.2022.123388.

Majeed IB, Nwulu NI, 2022. Impact of reverse power flow on distributed transformers in a solar-photovoltaic-integrated low-voltage network. Energies, 15 (23), doi:10.3390/en15239238.

Mamun KA, Islam FR, Haque R, Chand AA, Prasad KA, Goundar KK, Prakash K, Maharaj S, 2022. Systematic modeling and analysis of on-board vehicle integrated novel hybrid renewable energy system with storage for electric vehicles. Sustainability, 14 (5), 2538, doi:10.3390/su14052538.

Meng Y, Li X, Liu X, Cui X, Xu P, Li S, 2021. A control strategy for battery energy storage systems participating in primary frequency control considering the disturbance type. IEEE Access, 9, 102004–18, doi:10.1109/ACCESS.2021.3094309.

Mexis I, Todeschini G, 2020. Battery energy storage systems in the United Kingdom: A review of current state-of-the-art and future applications. Energies, 13 (14), 3616, doi:10.3390/en13143616.

Mohamed AAR, John Morrow D, Best RJ, Bailie I, Cupples A, Pollock J, 2020. Battery energy storage systems allocation considering distribution network congestion. IEEE

PES Innovative Smart Grid Technologies Europe (ISGT-Europe), doi:10.1109/ISGT-Europe47291.2020.9248982.
Nair UR, Sandelic M, Sangwongwanich A, Dragičević T, Costa-Castelló R, Blaabjerg F, 2021a. An analysis of multi objective energy scheduling in PV-BESS system under prediction uncertainty. IEEE Transactions on Energy Conversion, 36 (3), 2276–86, doi:10.1109/TEC.2021.3055453.
Nair UR, Sandelic M, Sangwongwanich A, Dragičević T, Costa-Castelló R, Blaabjerg F, 2021b. Grid congestion mitigation and battery degradation minimisation using model predictive control in PV-Based microgrid. IEEE Transactions on Energy Conversion, 36 (2), 1500–1509, doi:10.1109/TEC.2020.3032534.
Peng CY, Kuo CC, Tsai CT, 2021. Optimal configuration with capacity analysis of PV-plus-BESS for behind-the-meter application. Applied Sciences, 11 (17), 7851, doi:10.3390/app11177851.
Prajapati VK, Mahajan V, 2021. Reliability assessment and congestion management of power system with energy storage system and uncertain renewable resources. Energy 215, 119134, doi:10.1016/j.energy.2020.119134.
Prakash K, Ali M, Siddique MNI, Karmaker AK, Macana CA, Dong D, Pota HR, 2022. Bi-level planning and scheduling of electric vehicle charging stations for peak shaving and congestion management in low voltage distribution networks. Computers and Electrical Engineering, 102, 108235, doi:10.1016/j.compeleceng.2022.108235.
Prakash K, Ali M, Siddique MNI, Chand AA, Kumar NM, Dong D, Pota HR, 2022. A review of battery energy storage systems for Ancillary Services in Distribution Grids: Current status, challenges and future directions. Frontiers in Energy Research, 10, doi:10.3389/fenrg.2022.971704.
Prastia R, Asran A, Hasibuan A, Rosdiana R, Ezwarsyah E, 2024. Analysis of voltage drop improvement using transformer insertion method in LG-02 receiver Lhokseumawe City. Applied Engineering, Innovation, and Technology, 1 (1), 47–58, doi:10.62777/aeit.v1i1.19.
Rahman T, Alharbi T, 2024. Exploring lithium-ion battery degradation: A concise review of critical factors, impacts, data-driven degradation estimation techniques, and sustainable directions for energy storage systems. Batteries, 10 (7), 220, doi:10.3390/batteries10070220.
Ramos A, Tuovinen M, Ala-Juusela M, 2021. Battery energy storage system (BESS) as a service in Finland: Business model and regulatory challenges. Energy Storage, 40, 102720, doi:10.1016/j.est.2021.102720.
Rana R, Berg K, Degefa MZ, Löschenbrand M, 2022. Modelling and simulation approaches for local energy community integrated distribution networks. IEEE Access, 10, 3775–89, doi:10.1109/ACCESS.2022.3140237.
Roy A, Meshram S, Patil RB, Arun S, Kore A, 2024. Life cycle testing and reliability analysis of prismatic lithium-iron-phosphate cells. International Journal of Sustainable Energy, 43 (1), 2337439, doi:10.1080/14786451.2024.2337439.
Soleimani M, Kezunovic M, 2020. Mitigating transformer loss of life and reducing the hazard of failure by the smart EV charging. IEEE Transactions on Industry Applications, 56 (5), 5974–83, doi:10.1109/TIA.2020.2986990.
Speake A, Fontanini A, Adhikari, R, White P, Munankarmi P, Yip A, 2025. Integration of electric vehicle charging loads in residential building stock energy modeling. NREL/TP-5500-93766, accessed 1 May 2026 from: https://www.nrel.gov/docs/fy25osti/93766.pdf.
Srivastava P, Haider R, Nair VJ, Venkataramanan V, Annaswamy AM, Srivastava AK, 2023. Voltage regulation in distribution grids: A survey. Annual Reviews in Control, 55, 165–81, doi:10.1016/j.arcontrol.2023.03.008.

Standards New Zealand, 2023. Residential electric vehicle (EV) charging- SNZ PAS 6011:2023. Version SNZ PAS 6011:2023, accessed 8 October 2025 from: https://www.standards.govt.nz/shop/snz-pas-60112023.

Standards New Zealand, 2025. Residential solar photovoltaics (PV) and battery storage systems guideline-SNZ PAS 6014:2025. Ministry of business, innovation and employment. Version SNZ PAS 6014:2025, accessed 8 October 2025 from: https://www.standards.govt.nz/shop/SNZ-PAS-60142025.

Stecca M, Elizondo LR, Soeiro TB, Bauer P, Palensky P, 2020. A comprehensive review of the integration of battery energy storage systems into distribution networks. IEEE Open Journal of the Industrial Electronics Society, 1, 46–65, doi:10.1109/OJIES.2020.2981832.

Syahbani MA, Ramli MAM, Megantoro P, Ardiansyah A, Cahyani ID, Dinata NFP, Firmansyah R, Zohri M, Budiman FN, 2025. Performance enhancement of grid-forming inverter-controlled PV systems: A comparative study with and without battery energy storage under intermittent and unbalanced load conditions. Results in Engineering, 27, 105980, doi:10.1016/j.rineng.2025.105980.

Tewari T, Mohapatra A, Anand S, 2021. Coordinated control of OLTC and energy storage for voltage regulation in distribution network with high PV penetration. IEEE Transactions on Sustainable Energy, 12 (1), 262–72, doi:10.1109/TSTE.2020.2991017.

Tounsi F, Willy S, Saulo M, Ngoo L, 2022. Controlled electric vehicle charging for reverse power flow correction in the distribution network with high photovoltaic penetration: Case of an expanded IEEE 13 node test network. Heliyon, 8 (3), e09058, doi:10.1016/j.heliyon.2022.e09058.

Transpower, 2026. A Future grid blueprint for Aotearoa Te Kanapu consultation 3 - Future direction. Wellington, accessed 5 January 2026 from: https://static.transpower.co.nz/public/uncontrolled_docs/Te%20Kanapu%20Consultation%203%20-%20Future%20Direction.pdf?VersionId=RM.d9lb1bBaN.njfNPmgnirt0Ok2PHki.

Uzum, B, Onen A, Hasanien HM, Muyeen SM, 2021. Rooftop solar PV penetration impacts on distribution network and further growth factors—A comprehensive review. Electronics, 10 (1), 55, doi:10.3390/electronics10010055.

Wang L, Dubey A, Gebremedhin AH, Srivastava AK, Schulz N, 2022. MPC-based decentralized voltage control in power distribution systems with EV and PV coordination. IEEE Transactions on Smart Grid, 13 (4), 2908–19, doi:10.1109/TSG.2022.3156115.

Wang X, Zhang J, Shang B, Zhou N, Xu M, Wang P, Song H, Zhang Q, 2024. Key technologies and applications of cloud-edge collaborative integrated low and medium voltage distributed photovoltaic coordination control. Journal of Physics: Conference Series, 2757 (1), 012006, doi:10.1088/1742-6596/2757/1/012006.

Wellington Electricity, 2025. Asset management plan. Wellington, accessed 5 January 2026 from: https://www.welectricity.co.nz/disclosures/asset-management-plan/document/336.

Yu SY, Kim HJ, Kim JH, Han BM, 2016. SoC-based output voltage control for BESS with a lithium-ion battery in a stand-alone DC microgrid. Energies, 9 (11), 924, doi:10.3390/en9110924.

Zhao T, Parisio A, Milanović JV, 2021. Location-dependent distributed control of battery energy storage systems for fast frequency Response. International Journal of Electrical Power & Energy Systems, 125, 106493, doi:10.1016/j.ijepes.2020.106493.

Zheng L, An Z, Mauger MJ, Kandula RP, Divan D, Grijalva S, 2021. A charging strategy for electric vehicle fast charging station to mitigate distribution transformer aging and reduce operation cost. IEEE Industry Applications Society Annual Meeting, doi:10.1109/IAS48185.2021.9677252.

Zheng L, Marellapudi A, Chowdhury VR, Bilakanti N, Kandula RP, Saeedifard M, Grijalva S, Divan D, 2022. Solid-state transformer and hybrid transformer with integrated energy storage in active distribution grids: Technical and economic comparison, dispatch, and control. IEEE Journal of Emerging and Selected Topics in Power Electronics, 10 (4), 3771–87. Scopus, doi:10.1109/JESTPE.2022.3144361.

Zheng QY, Catun S, Mohammed MMM, Lu CN, 2025. Unlocking virtual feeder hosting capability for renewable integrations via P2P ancillary service trading. IEEE Transactions on Industry Applications, doi:10.1109/TIA.2025.3567412.